STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

FILED

SEP 0 1 2006

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC. ("VECTREN SOUTH-GAS") FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) AUTHORITY, TO THE EXTENT NECESSARY AS AN ALTERNATIVE REGULATORY PLAN, TO RECOVER ITS UNACCOUNTED FOR GAS COSTS AND THE GAS COST COMPONENT OF ITS BAD DEBT EXPENSE IN ITS GAS COST ADJUSTMENT FILINGS; (4) APPROVAL OF A DISTRIBUTION REPLACEMENT ADJUSTMENT TO RECOVER THE COSTS OF A PROGRAM FOR THE ACCELERATED REPLACEMENT OF CAST IRON MAINS AND BARE STEEL MAINS AND SERVICE LINES; (5) APPROVAL OF THE IMPLEMENTATION OF THE SALES RECONCILIATION COMPONENT OF THE ENERGY EFFICIENCY RIDER PROPOSED IN CAUSE NOS. 42943 AND 43046 OR OTHER RATE DESIGN CHANGES THAT UNLINK ITS FIXED COST RECOVERY FROM ITS SALES VOLUME; (6) APPROVAL AS AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-6 OF A RETURN ON EQUITY TEST TO BE USED IN LIEU OF THE STATUTORY NET OPERATING INCOME TEST IN ITS GAS COST ADJUSTMENT PROCEEDINGS; (7) AUTHORITY PURSUANT TO 170 IAC 5-1-27(F) FOR A NON-GAS COST REVENUE TEST TO DETERMINE WHEN DEPOSITS ARE REQUIRED FOR FACILITIES EXTENSIONS; AND (8) APPROVAL OF VARIOUS CHANGES TO ITS TARIFF FOR GAS SERVICE, INCLUDING INCREASES IN CERTAIN NON-RECURRING CHARGES.

CAUSE NO. 43112

Prepared Direct Testimony and Exhibits
of
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH – GAS)

Book 1 of 3

JA Benkert, MS Hardwick, RC Sears, PR Moul, RL Goocher

September 1, 2006

VECTREN SOUTH Gas Rate Case
Table of Contents
Case in Chief List of Witnesses and Exhibits

Case in Chief Book 1 filed 9-01-06

Case in Chief Book 2 filed 9-01-06

Case in Chief Book 3 – Subsequent filing:

**SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH – GAS)**

IURC CAUSE NO. 43112

DIRECT TESTIMONY

OF

**JEROME A. BENKERT, JR.
EXECUTIVE VICE PRESIDENT AND CHIEF FINANCIAL OFFICER**

ON

CASE OVERVIEW AND POLICY MATTERS

SPONSORING PETITIONER'S EXHIBIT NO. JAB-1

DIRECT TESTIMONY OF JEROME A. BENKERT, JR.

Introduction

Q. Please state your name and business address.

A. My name is Jerome A. Benkert. My business address is One Vectren Square, Evansville, Indiana 47708.

Q. What is your position with Southern Indiana Gas & Electric Co. Inc., d/b/a Vectren Energy Delivery of Indiana, Inc., ("Vectren South Gas" or "Company")?

A. I am Executive Vice President and CFO of Vectren South Gas. I also hold these same positions with Vectren Corporation ("Vectren"), Vectren Utility Holdings, Inc. ("VUHI"), Indiana Gas Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren North") and Vectren Energy Delivery of Ohio, Inc. ("Vectren Ohio").

Q. What is your educational background?

A. I graduated from Indiana University in 1980 with a Bachelor of Science degree with a concentration in accounting.

Q. Please describe your business experience.

A. I have over 20 years experience in various executive, financial and administrative roles, primarily in the utility and energy industry. I have worked at Vectren and its predecessor companies in a variety of positions including Assistant Treasurer, Vice President and Controller, and Executive Vice President and COO of Indiana Energy's administrative services company. Since Vectren's formation I have held the position of executive vice president and CFO and for a brief period, treasurer. I began my career as a CPA with five years of public accounting. I am a director of VUHI, Vectren North, Vectren South and Vectren Ohio, as well as a number of Vectren's non-regulated subsidiaries and affiliates. In addition, I have also been appointed to the board of directors of Fifth Third Bank, Indiana (Southern) and Deaconess Hospital of Evansville, Indiana.

Q. What are your responsibilities as CFO of Vectren and its regulated subsidiaries?

A. As an executive officer I am responsible for policy and governance. In my role as CFO, I am responsible for capital attraction and risk management. Functional areas reporting to me include Treasury, Investor Relations, Accounting and Tax, and Regulatory Affairs and Fuels.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony in this case will provide an overview of the case, which will highlight Vectren South's inadequate financial performance, its current risk profile and credit ratings, the relationship of this case to the pending Efficiency Settlement, and the Company's proposals to address the aging workforce and replacement of aging infrastructure.

<u>Overview of Case</u>

Q. Please describe the business of Vectren South Gas.

A. Vectren South is a public utility that supplies both electricity and natural gas and natural gas transportation service to the public in Southwestern Indiana. Among other things, Vectren South owns, operates, manages and controls plant, property, equipment and other facilities used for the acquisition, storage, transmission, transportation, distribution and sale of natural gas to residential, commercial, industrial and other customers in Southern Indiana. As of June 30, 2006, Vectren South Gas provided natural gas service to more than 112,000 customers in this area.

Q. Please explain the organizational structure of Vectren and VUHI, and describe the services provided to Vectren South by VUHI and Vectren.

A. Vectren is the publicly traded parent company of Vectren South, formed by the merger of SIGCORP, Inc. and Indiana Energy, Inc. in March 2000. On October 31, 2000, Vectren acquired the gas distribution assets of the Dayton Power and Light Company. Vectren's three utility subsidiaries provide regulated gas and electric services to over one million customers in Indiana and Ohio. Vectren also has non-utility subsidiaries and investments that engage in energy marketing, coal mining, energy infrastructure and other energy related activities. Certain administrative functions such as accounting and human resources are performed by Vectren personnel on behalf of Vectren South.

VUHI is an intermediate holding company wholly owned by Vectren. Apart from holding Vectren's equity interest in three utilities (Vectren North, Vectren Ohio and Vectren South), VUHI provides "shared services" to the utilities derived from the use of assets such as the information technology resources used to maintain customer records and the call center used to handle all customer calls. VUHI has also received Commission approval to provide financing to the utilities. By pooling the financing requirements of its utility subsidiaries, VUHI is able to raise funds more efficiently, and on more attractive terms. This reduction in financing costs benefits customers.

Q. What is the requested rate increase for Vectren South in this case?

A. Vectren South is requesting a base rate increase of $10.4 million or 6.7%.

Q. Please summarize the need for Vectren South's request for a base rate increase.

A. From a financial perspective, Vectren South Gas has performed poorly for many years, essentially leaning heavily on the financial results of Vectren South's electric operations for credit support rather than maintaining a standalone level of financial performance adequate to support solid credit ratings. In 2002, 2003, and 2004 (new rates became effective on July 1, 2004) Vectren South achieved equity returns of 5.65%, 3.32%, and 3.26% respectively. These earned returns fall below even the cost of new debt and clearly fail to adequately compensate equity investors. Prior to the 2004 Order, Vectren South Gas' base rates had been set in an order issued on July 3, 1996.

Based upon Vectren South Gas' declining financial performance, on March 12, 2004 Vectren South filed a petition seeking a base rate increase. As set forth in its Testimony filed in support of the settlement, using a test year ended December 31, 2002, Vectren South Gas showed a need for a $14.7 million revenue increase, mostly driven by the fact that since its last rate case gas plant in service had grown from $171.8 million to $191.1 million, a $19.3 million increase.

Based on negotiations that occurred throughout 2003 prior to filing the petition for relief, on March 26, 2004, the OUCC and Vectren South filed a Stipulation providing for an agreed upon $5.7 million revenue increase (the "2004 Settlement"). The Commission approved the 2004 Settlement on June 30, 2004. As a result, on July 1, 2004 Vectren South implemented a 5% rate increase.

The agreed upon rate increase has proven to be insufficient to provide Vectren South Gas with a reasonable return on its gas operations. In 2005, despite the new rates being in effect for the entire year, Vectren South achieved a return on equity of only 2.5%. For 2006, Vectren South Gas projects a similar, inadequate return. Absent a rate increase, 2007 financial results will deteriorate even further. Given the expected timing of an order in this case, Vectren South Gas will, at best, earn an inadequate return for the first half of 2007. Thus, Vectren South Gas operations on a stand alone basis continue to not support its credit rating, and absent continued reliance on the overall finances of Vectren South Electric, Vectren South Gas would not be able to maintain its A-/Baa1 credit rating and would likely not be able to raise capital at a reasonable cost and on reasonable terms.

<u>The 2004 Rate Case Settlement</u>

Q. Is Vectren South Gas' continued poor financial performance the result of a dramatic change in operating conditions since the 2004 Settlement?

A. No. Certainly, many of the identified challenges facing the utility in 2004 remain, and will be described in this proceeding. However, in 2004, for a variety of reasons Vectren South Gas knowingly agreed to a rate increase amounting to less than 40% of its request, and predictably this has necessitated another rate case with a test year that ends 39 months after the prior test year. In support of the 2004 Settlement, Vectren South Gas explained the rationale for its agreement to the smaller rate increase as follows:

In order to achieve a Settlement, Vectren South has, in the spirit of the compromise, agreed to a rate increase considerably less than it would have sought without the Settlement. There are six principal reasons for doing so.

First, the OUCC made it clear that it would vigorously contest certain aspects of Vectren South's position, particularly with respect to the requested return. Therefore, the alternative to Settlement is a lengthy adversarial process that would be expensive, time consuming and require the dedication of substantial additional resources.

Second, Vectren South's expectation is that the Commission will be able to expeditiously approve the Settlement. This will afford rate relief to Vectren South sooner that would otherwise be the case. As shown on page 7 of the Settlement, the OUCC agreed to support prompt approval. Timeliness of this increase, given the current low level of return being generated, was the primary motivating factor for Vectren South in accepting the negotiated terms.

Third, resolving the Pipeline Safety Act issue promptly was also an important consideration because of the statutory deadlines driving the need to commence compliance activities this year. The implementation of a tracker for recovery of the compliance costs will reduce risk and uncertainty for both the Company and the customer.

Fourth, as previously discussed, the manner of implementing the agreed upon increase will protect the additional revenue from significant weather risk.

Fifth, the level of increase is over 60% less than the case-in-chief filed by Vectren, therefore customer rates will go up less significantly. Given the amount of time between rate cases, and the intervening rate base investment, the Settlement which reduces the amount of the increase balances Vectren's legitimate need for an increase with customer interest in stable rates and low cost service.

Sixth, the Settlement is consistent with the policy of Vectren South and its affiliates to seek to foster good relations with regulators, the consumers' statutory representatives and individual customers, large and small. We believe that collaboration and consensus building can often best achieve a balanced resolution consistent with the goals of all parties.

(Cause No. 42596, Pet. Ex. JAB-5, p. 11).

Q. How have Vectren South Gas' customers been affected by the 2004 Settlement?

A. For a long period, Vectren South Gas' customers have enjoyed low rates. As stated above, for a number of years this has meant the Company earned very poor returns. In support of the 2004 Settlement, the OUCC filed testimony explaining their perspective on the agreed upon rate increase. In that testimony the OUCC stated: "The OUCC views Vectren South Gas as a low cost leader in the provision of natural gas service in Indiana, and any negotiated resolution needs to maintain Vectren South Gas' leadership position as a low cost provider to both small and large customers." (Cause No. 42596, Public's Ex. No. 1, p. 5). In that testimony, the OUCC pointed out that the Commission's annual ranking of residential gas bills has consistently shown Vectren South Gas to be one of the lowest cost utilities in Indiana. In terms of the reasonableness of the agreed upon rate increase, the OUCC concluded, "Perhaps the single greatest factor causing me to support the Settlement Agreement is that, even with this proposed increase, Vectren South Gas will remain very competitive as a low cost provider of natural gas utility service to both residential customers and very large customers like ALCOA." (Id., p. 8).

For the five year period of 2002-2006, Vectren South customers' rates were the third lowest in the state.

This discussion sets the context for this "follow on" rate case. Vectren South Gas obtained certain benefits from the 2004 Settlement including timely approval of new rates and a tracker for recovery of new costs related to the enactment of the Pipeline Safety Act. In settling for less than half of its requested rate increase, Vectren South Gas anticipated that it would obtain a portion of the required rate increase and then in this subsequent rate case essentially phase in the remaining necessary rate increase. In the meantime, its customers have continued to benefit from very low rates. This case recognizes that at some point, Vectren South Gas must be able to achieve reasonable financial performance that allows it to stand on its own in terms of operating a reliable system, attracting capital and providing quality service to its customers.

Overview of Vectren South Challenges

Q. You have referenced ongoing challenges facing Vectren South Gas that were raised during the prior rate case. Please identify and explain these challenges.

A. At the time of the 2004 rate case, Vectren South identified the following significant issues facing the company: (1) capital attraction, both due to the changed perception of risk associated with the utility industry, as well as uncertain earnings due to non-normal weather, (2) reduced customer usage, (3) the negative affects of high natural gas prices, (4) reduced customer growth, and (5) environmental risks associated with the cleanup of Manufactured Gas Plant (MGP) sites. In late 2002, Moody's downgraded Vectren South from A2 to Baa1 for its unsecured long-term debt. As stated in my testimony in 2004, in the aftermath of highly public struggles by many well known energy companies, the financial markets downgraded many utilities, and have since placed great value on earnings stability. This emphasis is demonstrated by specific reports and studies that Moody's has published on weather risk and mitigation as well as declining usage and decoupling mechanisms.

Q. Has Vectren South taken steps to address any of these issues since the 2004 Settlement?

A. Yes. With the support of the OUCC and Commission, Vectren South Gas has addressed the volatility in year to year to financial performance posed by abnormal weather through implementation of a Normal Temperature Adjustment mechanism ("NTA") on October 15, 2005. In addition, in a pending proceeding, Vectren South Gas has filed a settlement with the OUCC designed to promote customer efficiency and provide a remedy to the adverse impact of declining customer usage on recovery of fixed costs through a Sales Reconciliation Component that reconciles margin based on actual customer sales with rate case approved margin (the "SRC") (Cause No. 42943). Together, the NTA and the proposed Efficiency Settlement in Cause No. 42943, if approved, address margin volatility associated with residential and small commercial customers. Under the Efficiency Settlement, if approved, Vectren South Gas will have rates as part of the outcome of this case that are delinked from sales. The NTA and SRC mechanisms together provide the Company with a rate design that supports a better opportunity to actually achieve the level of cost recovery authorized by the Commission. At the same time, because both the NTA and the proposed sales reconciliation mechanism to address usage are symmetrical in nature, the Company no longer has the upside sales opportunity associated with colder than normal winters, or other increases in the level of small volume customer usage. Thus, these mechanisms truly serve to smooth out financial results, and reduce risk to both customers and the Company related to volatile margins. However, these mechanisms do not address changes in large customer usage, nor changes in operating and maintenance costs, nor return on new investment, nor increased interest rates among other business risks. They simply improve on volumetric rate design and recognize the trend of warm winters and declining sales and importantly, allow the company to advocate and sponsor conservation and reduced usage to Vectren South Gas' customers.

To protect customers from prevailing gas market volatility, Vectren South Gas continues to use a portfolio approach to gas purchasing designed to help mitigate gas price volatility. This includes its advanced purchases at fixed prices, storage injections as well as some financial hedging. These efforts have been highly successful, but the market has seen unprecedented spikes in price, and as a result customers have incurred higher gas costs over the past few years. As discussed in the 2004 case and in this case, high gas costs continue to drive increases in a number of operating costs, including hiring more employees in the call center to handle increasing levels of customer calls related in one way or another to high gas costs, and increased bad debt expense.

With respect to Manufactured Gas Plant (MGP) remediation, Vectren South has begun to incur costs as it investigates five MGP sites and develops its remediation plans to submit to the Indiana Department of Environmental Management. Vectren South is not seeking recovery of these costs in this case, but has initiated a lawsuit in order to pursue insurance recoveries to help fund such costs.

Q. The NTA and the potential approval of the Efficiency Settlement in Cause No. 42943 address the uncertainty associated with volumetric rate design. Is this change detrimental to customers?

A. No. In fact, if approved, Vectren South Gas customers will benefit from all of the efficiency programs envisioned in the Efficiency Settlement, even before the ratemaking design is put in effect. Further, customers benefit when the utility produces stable cash flows, financial results and attendant strong credit ratings. For decades, Vectren South has billed customers using volumetric rates. For the earlier portion of this period, this rate design did not pose asymmetrical risk to the Company due to more stable usage patterns and sales growth. Thus, the Company had a reasonable opportunity to recover its costs, including a reasonable return, over time. Under a lower gas cost environment, there was better opportunity to maintain or grow gas margins and to limit or control cost increases. Thus, while volumetric rate design inherently posed the risk that sales would not be at the level projected in the rate case, this rate design risk was truly symmetrical in nature.

A number of factors have undermined this symmetry over the past 5 years or so. As described in the Efficiency Settlement, greater efficiency in homes and appliances has driven customer use consistently downward and at greater rates of decline. This trend existed before the price spikes commenced in 1999/2000. Specifically, gas prices and volatility have escalated this downward trend over the last two years, resulting in dramatic sales declines. High gas costs have also increased interest expense and bad debt expense and other costs. The result has been that more and more financial risk has been shifted to Vectren South over this period—yet higher returns have not been achieved as compensation for such risk that is tied to use of traditional volumetric rate design. For all of these reasons, if for some reason the Efficiency Settlement is not approved, Vectren South would still seek modification of volumetric rate design in this case through adoption of the SRC or an alternative to the SRC that would similarly be intended to eliminate the link between customer usage and fixed cost recovery for the residential and general service classes. The inability to accurately project future sales makes continued use of traditional volumetric rate design untenable.

Q. Have the credit agencies expressed any concerns related to declining customer usage?

A. Yes. In December 2004, Moody's issued its periodic National Gas Transmission & Distribution Sector outlook report. In discussing the impact of high natural gas prices, Moody's expressed its opinion that over time, high gas prices could cause demand destruction. Moody's noted that, "The secular decline in per-consumer usage has eroded LDCs' gross margins and returns at a time when operating and capital costs are on the rise." (Moody's Industry Outlook, December 2004, p. 3). Moody's followed with a Special Comment in June 2005 titled, Impact of Conservation On Gas Margins and Financial Stability in the Gas LDC Sector. In that commentary, Moody's reviewed the trend of declining average use per customer and the resulting impact on LDC margin. Based on the correlation between rising gas prices and diminished customer use, Moody's expressed its belief that an increasing number of LDCs would seek some form of rate design modification. Moody's concluded with its belief that "having utility rate designs that compensate the gas LDCs for margins lost on account of variations in conservation as with variations in weather, would serve to stabilize a utility's credit metrics and credit ratings." (Special Comment, June 2005, p. 8).

This customer conservation issue remains at the forefront of Moody's consideration of the LDC industry. In June 2006, Moody's issued another Special Comment that tracks progress on this policy issue. In this Special Comment, Moody's came out more strongly on the need for rate design modification, stating that the volumetric recovery of fixed costs "is a faulty equation which needs to be rectified in ratemaking [and] unless and until this anomaly is corrected, the LDC would lack the necessary tools with which to earn its allowed rate of return." (Special Comment, June 2006, p.4). Moody's conveyed a clear message to all industry stakeholders when it stated that the "difference between those companies that have RD [revenue decoupling] and those that do not will tend to be further accentuated as the credit demarcation reflected through rating actions becomes more evident." (Id., at p.1). Adoption of the SRC should be viewed as necessary and timely from the standpoint of supporting credit ratings.

Adoption of the Efficiency Settlement overall continues to remain very important from a customer standpoint to allow the Company to promote conservation.

Q. If the objective of rate design is to create rates that provide a reasonable opportunity for Vectren South to recover its authorized costs, should the NTA and approval of the proposed Efficiency Settlement result in a reduction to Vectren South's authorized cost of capital?

A. No. As a practical matter, it would be very difficult to increase returns to a level sufficient to fully compensate for volumetric rate design that can cause a gas utility in a period of declining sales to miss its level of authorized cost recovery by millions of dollars in a given year. Of late, this situation has gotten much worse given even more significant reduction in usage per customer.

Moreover, if rate design should serve the purpose of accurately providing a fair opportunity to recover an approved level of costs, then traditional volumetric rate design must be considered a poor tool for achieving this outcome. Replacing such an imperfect rate design with a more accurate mechanism does not harm customers and does not diminish utility business risk in a manner that justifies reducing its cost of capital. Actual recovery of reasonable fixed costs cannot be viewed as harmful to customers. Moreover, utilities should not be punished for proactively moving to a model of promoting conservation and usage declines to the benefit of their customers. Vectren South has competed for capital for years with many utilities that had NTAs. And the peer group utilized by Vectren South Witness Paul Moul for preparation of our cost of equity request is replete with many examples of weather, usage and other risk mitigation regulatory designs. Yet, Vectren South's allowed return on equity was no higher than its peers that had NTAs. For example, Vectren South's current allowed return of 10.5% is lower than that of Atlanta Gas Light, a gas utility that has fixed variable (non-volumetric) rates and does not sell gas to its customers, thereby avoiding many risks associated with providing gas supply. Ultimately, a rate design that provides a more accurate means of providing cost recovery recognizes the nature of the gas distribution business as a largely fixed cost enterprise.

Correcting faulty rate design still leaves Vectren South facing many other business challenges that are typical in the gas industry.

Q. Apart from ongoing challenges associated with high and volatile gas costs discussed above, are there additional challenges that Vectren South seeks to address in this proceeding to support its continued provision of reliable service to its customers?

A. Yes. In this proceeding, Vectren South will make proactive proposals to address two significant issues that have received growing attention from the entire energy industry --- (1) an aging workforce nearing retirement in a concentrated time period, and (2) aging infrastructure that results in high leak rates and should be replaced. Vectren South has considered how best to address these issues in an effective manner that avoids negative impact to the Company and its customers. Getting out in front of both of these issues is very much in the interest of the Company's customers.

Q. Do you have any final comment related to high gas costs and "demand destruction"?

A. Yes. Moody's 2006 report references demand destruction in the gas industry over time. While the SRC addresses declining sales per residential and commercial customer, no regulatory mechanism exists to address residential or large customer fuel switching or large customers going out of business. Less than a decade ago, gas utilities served the asphalt and grain drying industry. That service relationship no longer exists because gas is too expensive for these businesses.

High gas prices threaten cost competitiveness and create a potential dilemma where gas utilities lose customers without losing fixed costs, making it harder to spread costs and retain remaining customers. Gas prices hurt customer satisfaction and drive up operating costs, but in the long run, the threat to cost competitiveness represents a serious concern for all gas utilities. In the short-term, efficiency programs must be pursued to relieve supply pressure and reduce prices. In the meantime, in the present era, where a hurricane or a cold week can drive gas prices above $10 per dth, the gas distribution business is more risky than it has ever been.

Current Credit Ratings/Analysis

Q. What are Vectren South's current credit ratings?

A. Because Vectren South provides both electric and gas service, its ratings reflect an overall analysis of both the Vectren South Gas operations (considered in this case) and Vectren South Electric operations. Moody's Investors Service has rated Vectren South Baa1, with a stable outlook. Standard & Poor's has rated Vectren South A-, with a stable outlook.

Q. In the opinion of the rating agencies, what are Vectren South's strengths?

A. Moody's lists the following credit strengths: (1) competitive rates, (2) generally supportive regulatory environment, (3) moderate capitalization, and (4) a new weather normalization mechanism.

Standard & Poor's lists the following credit strengths: (1) strong franchise, (2) no electric industry restructuring, (3) diversity of electric and gas operations, (4) favorable regulatory treatment of pollution control expenditures, and (5) low electric production costs.

As anticipated, both agencies removed the lack of weather normalization for the gas utility as a significant credit weakness, and have listed approval of the NTA as a credit strength. Adoption of the NTA placed Vectren South Gas on more equal footing with many of its peers.

Q. In the opinion of the rating agencies, what are Vectren South's weaknesses?

A. Moody's identifies three main credit challenges: (1) dependency on coal-fired plants leading to added capital expenditures, (2) contingencies related to NO_x expenditures and future environmental regulations, and (3) margin impact from gas conservation by customers.

Standard & Poor's identifies three different credit weaknesses: (1) industrial and commercial customer concentration which is vulnerable to economic downturns, (2) operational risk in its electricity generation and distribution business, and (3) assets and fuel concentration due to the electric generating capacity being mostly coal-fired.

As discussed by Vectren South Witness Robert L. Goocher, Vectren South's goal is to be A rated. Supportive regulatory action in this proceeding is necessary to help the Company continue to move fully there.

Rate Design

Q. Does Vectren South Gas propose to use the SRC provided for in the Efficiency Settlement to address the "faulty equation" created by use of volumetric rate design for recovery of fixed costs?

A. Yes, with one permitted change. The Efficiency Settlement in Cause No. 42943 provides that Vectren South Gas, having already implemented the efficiency program provided for in the Settlement, will wait to implement an SRC at the time the Commission approves its new base rates in this case (Settlement, Para. 23). The SRC does address the need to replace volumetric rate design so that fixed costs are recovered. The Efficiency Settlement provided Vectren South Gas with the opportunity to propose an alternative rate design to the SRC so long as the alternative served the same intent to eliminate the link between customer usage and cost recovery. (Settlement, Para. 36). The Parties also agreed that the order in this base rate case would not approve a rate design other than the SRC unless such design was consistent with the objectives of providing non-commodity cost recovery regardless of usage. (Id.). We propose to adopt the SRC without the 15% reduction discussed below.

Because the Efficiency Settlement took place after Vectren North and Vectren South's most recent rate cases, Vectren agreed to no SRC for Vectren South until the conclusion of this proceeding, and an SRC for Vectren North that recoups 85% of lost margins due to usage declines. In this proceeding, all of Vectren South's costs, including its cost of capital, are being reviewed. Therefore, there is no reason to implement an SRC that provides less than full margin recovery. No one would propose an SRC that allows Vectren South to retain 15% of margins above its rate case authorized margins if sales increase. Likewise, once rates are designed to recover fixed costs, there is no reason to hold back some of this recovery.

As OUCC witness Bolinger in the efficiency case noted as a possibility, in this case, given recent usage declines Vectren South has a test year that represents a very low level of customer sales. Market price volatility will likely have an impact on future sales level, but with the SRC, if usage does not remain at such a low level next year, customers will not pay more than the rate case authorized margins. This symmetry is fair and beneficial, and providing an reduction to the SRC in the aftermath of a full rate proceeding makes no sense.

The outcome of this case should be that once the Commission determines the revenue requirement required to reasonably operate the distribution system, assuming this rate design is implemented, for the first time in many years, Vectren South may have a reasonable opportunity to recover that authorized revenue requirement.

Aging Workforce

Q. Earlier you mentioned the looming retirement of a large portion of Vectren South's skilled workforce as a significant issue for the Company. Please comment on Vectren South's proposal to meet this challenge.

A. As a member of Senior Management, over the past two years, I have personally participated in numerous discussions involving key representatives of our Human Resources and Operations areas where this topic has received attention. We have studied the issue in depth, benefiting from information and ideas other companies have developed as they react to the changing demographics of the workforce.

Other witnesses will address how we intend to replace these valuable employees. What I want to emphasize is that Vectren South is taking this issue very seriously and is spending the time necessary to thoughtfully respond to the issue. Further, Vectren South will use the requested cost recovery to hire qualified men and women to replace the retirees consistent with the plans set forth in this case. We ask the Commission to support these important efforts. We are essentially laying the foundation of our future ability to operate reliably by hiring these employees now and spending the requisite time to adequately train them to perform their jobs.

System Improvement

Q. Has gas pipeline system condition become a focal point for regulators in recent years?

A. Yes. Four years ago, Congress passed the Pipeline Safety Improvement Act of 2002 requiring the U. S. Department of Transportation (DOT) to create rules to require all pipeline generators to assess their high pressure non-distribution lines in certain areas, essentially tied to density of population. This newly required integrity assessment activity has begun.

Currently, the DOT is working on similar rules related to distribution pipeline integrity. These rules are anticipated to be finalized in 2007. Apart from the DOT rules, some states have ordered gas utilities to engage in programs to replace older pipes.

These events stem from both highly publicized incidents involving pipelines that have led to loss of property and life, as well as a growing awareness that the pipeline infrastructure currently being relied upon contains many miles of older pipe installed prior to the advent of better materials and construction methods. In fact, many bare steel and cast iron pipelines still in use today have not been allowed for new installations since DOT first put minimum pipeline safety standards in place in 1971.

Q. Please explain why Vectren South Gas seeks a tracker to recover costs associated with its replacement of these older pipes.

A. As discussed in detail by Vectren South Witness James Francis, Vectren South believes that aggressively removing these pipes from service will be beneficial to ongoing system operations. The tracker proposal, modeled on a similar approach approved by the Ohio Public Utilities Commission to enable Cincinnati Gas & Electric Company to proceed with a more aggressive replacement program than the one proposed here, provides support for capital investment similar to the type of support provided with respect to electric utility expenditures on pollution control equipment. Vectren South Gas' current rate base stands at approximately $120 million. In order to replace all bare steel and cast iron lines, during the planned 20 year program Vectren South may invest as much as $90 million or more. Such a substantial under taking – incremental to the typical capital requirements to operate the system which will not go away—requires the company to raise additional debt and equity to accomplish the objectives of this important system improvement. Timely recovery of invested costs is needed to embark on this effort. Therefore, the tracker, which will be subject to annual reviews of both expenditures and the next year of proposed projects, as well as offsets for operating cost savings resulting from the project, provides needed financial support for the project.

<u>Bad Debt And Unaccounted For Gas Expenses</u>

Q. Does Vectren South propose to use the GCA to track changes related to bad debt and unaccounted for gas cost expenses?

A. Yes. Given the current high cost of natural gas and the volatility that is expected to continue in the future, tracking unaccounted for gas (UAFG) and the gas cost component of bad debts is proposed as the best answer for both the customer and Vectren South. UAFG is a gas cost and is uncertain in amount largely due to price changes. Similarly, because approximately 70% of customer bills are gas costs, today the majority of bad debts consist of gas costs. These gas costs should be part of the gas cost recovery mechanism. Just like the GCA, as these costs fluctuate in the future, customers will not pay more or less than the Company actually incurs for these items. In an era of highly volatile gas prices, this is the right answer.

<u>Incentive Compensation</u>

Q. Vectren South Witness M. Susan Hardwick has included in Vectren South Gas' pro forma adjustments the cost to the Company of Vectren's long term and short term incentive compensation plans. Please explain why these plans are necessary to attract and retain qualified employees.

A. Our employee incentive compensation plans are designed to attract, retain and motivate quality people in the Vectren workforce. The level of incentive expense is developed from market data coming from various sources, including the American Gas Association ("AGA") annual compensation surveys as well as information from our compensation consultants, Hay Group and Towers Perrin. These sources enable us to compare compensation on both a regional and national basis. Important to our approach to incentives are the behaviors upon which we focus. We have specific measures in areas such as safety, customer service and cost containment. Our belief is that our incentive plan positively rewards people to work safely, meet their budgets (to affect earnings) and deliver exceptional customer service. There are specific targets and metrics in each of these areas. As discussed by Vectren South Witness William S. Doty, we do expect increased retirements due to an aging workforce, but as a result of our compensation approach and overall positive work environment, excluding retirements we experience a very low turnover of personnel which results in a more efficient expenditure of training dollars. These plans impact all of our employees. They are part of compensation and benefits negotiated for by the Vectren South bargaining unit employees. The incentives that help attract, retain and motivate our tenured/highly skilled workforce also offer great benefit to our customers as well as our shareholders, in terms of safe and reliable operations. Offering competitive compensation has never been more important as we respond to the aging workforce and the holes it can potentially leave in our bargaining and non-bargaining workforce.

Q. How does Vectren South Gas compensation levels and programs compare to comparable utilities and the market in general?

A. Based upon compensation surveys conducted by the AGA, Hay Group and Towers Perrin, we generally find our base pay/wages to be slightly below average. However, total compensation is generally at the market's average with the utilization of incentives to motivate positive employee behaviors making up the difference. As a result, the incentives are clearly "pay at risk". In other words, based on market data, Vectren employees would have higher base compensation. Management has chosen to put "at risk" an increment of this base pay through incentives. If the target level is met, incentive pay is needed simply to bring the employees pay to market average. Our incentives are paid only when specific performance objectives are met. Unlike base pay/wages, incentives are not guaranteed. "Pay at risk" objectives include safety, customer service and cost control, which translates into earnings. Our analysis of compensation levels and programs included the AGA survey, a national survey that is specifically focused on utility positions closely matched in scope and responsibility. We also utilized recent Towers Perrin survey data that was drawn from over 100 utility/energy companies. They also provided general industry compensation data from over 750 companies. The Hay Group data provides an additional 30 utility/energy companies. The Vectren philosophy utilized in the Towers Perrin and Hay Group work states that base salary and annual incentives will be "competitive with the 50th percentile of a blend of comparably-sized utilities and general industry companies."

Q. How do the targeted incentive compensation amounts included by Witness M. Susan Hardwick in Vectren South Gas operating expenses compare to the total available amount of incentive compensation?

A. The incentive plan design contemplates three levels of rewards: threshold, target, and maximum. For non-executives and executives alike, Company objectives achieved at or below the threshold metrics yield zero incentive pay for participants. The plan design allows a linear progression from zero (threshold) to pay out at target levels, which is the amount included in the labor expenses supported by Vectren South Petitioner's Witness M. Susan Hardwick. Achievements above target are leveraged differently for non-executives than executives, and reflect the respective market data that determine total compensation for each group. For non-executives, there is a linear progression, from 100% at target to 150% at maximum achievement. For executives, incentive pay is leveraged from 100% at target to 200% at maximum. Plan design does not allow awards beyond maximum and is capped at 150% and 200% for the respective employee groups. The cost of all payments which exceed the target levels would be borne by the shareholders in this case.

Base objectives along with metrics for incentive pay are products of Vectren's annual budget process that establish aggressive yet attainable business goals. The budget as well as the incentive metrics are reviewed and approved by the Vectren Board of Directors, in consultation with their independent compensation consultant, Hay Group.

Q. Please describe the operational performance objectives which are part of the annual incentive plan.

A. Safety and customer service represent clear operational performance objectives. Safety in the workplace is measured by the number of OSHA recordable injuries incurred. The Vectren utility employees have had great success of reducing OSHA recordable injuries in the workplace since Vectren was formed. This objective provides an incentive to the employees to continue to achieve those good results.

Customer service is measured by three factors. They are overall customer satisfaction, customer satisfaction with specific contact points such as when customers request a new service to be added, and call center performance. Satisfaction is measured by various means, including direct customer contact and survey responses. We see clear customer benefits from our employees' great interest in customer satisfaction and safety.

Q. Please describe the financial objective of the annual incentive plan.

A. This measure is based on achievement of Vectren earnings per share ("EPS") targets set by the Board of Directors with reference to the annual budget. As employees act upon the objective, often it is in the form of finding more efficient ways to serve the customer, such as by utilizing technology and reducing costs. The incentive plan is an important part of the Company's efforts to control costs and maximize efficiencies, which over time have a favorable impact on customer costs.

Cost Containment

Q. Your testimony has addressed many issues that will require increases in operating costs. Has Vectren South taken any steps to contain the level of its operating costs over time?

A. Yes. As mentioned previously, the merger of IEI and SIGCORP produced many costs savings, especially in areas such as IT systems by avoiding cost duplication. Post-merger, we also, in a careful manner, have looked for ways to maximize the efficiency of our workforce.

Last year our latest effort launched is an internal effort called Asset Management Transformation (AMT). AMT is a study of how we perform our field work and the use of assets we use to support the work. AMT will be a multi-year effort which should assist Vectren South in capturing some cost savings through better use of our resources. Keys will be the success of technologies we implement to assist us in this effort, and the "buy in" of our employees to changes we make in the manner in which they perform work. To date, we have just begun to implement certain changes and additional technology investments will be made and refinements to processes will continue. AMT, while very much a work in progress, is an example of ongoing efforts to be efficient in the provision of service to our customers.

Earnings Test

Q. Does Vectren South propose adoption of a new methodology for calculation of the GCA earnings test?

A. Yes. Vectren South Gas proposes to adopt a Return on Equity (ROE) test as provided for in the Efficiency Settlement in lieu of the net operating income (NOI) test. The ROE Test will accommodate approval of the infrastructure replacement tracker proposed herein, whereas the current NOI Test would have to be adjusted so that Vectren South Gas would not have excess earnings due to that tracker. Like the SRC or similar alternative, to the extent the Efficiency Settlement is not approved, Vectren South Gas would still seek implementation of the ROE Test in this case. Rates are based upon the utility's investment at a point in time, and income is then authorized to support that level of investment. The ROE Test recognizes that investment changes over time, and allows the appropriate amount of income to change coincident with investment. The NOI Test is static and does not account for incremental investment. This is especially problematic for a utility that is heavily investing in additional infrastructure, which is exactly what Vectren South intends to do. Thus, the ROE Test is a superior test.

Q. What ROE rate does Vectren South propose be used for this purpose?

A. Vectren South proposed use of an ROE rate of 11.75. This rate is supported by Mr. Moul's testimony and has been used to determine Vectren South's proposed revenue requirement in this proceeding. This revenue requirement reflects application of the cost of capital (using an 11.75% ROE) applied to Vectren South's original cost rate base. This is a conservative measure of the required return because the testimony of Mr. Kelly and Mr. Moul shows that the fair value of Vectren South's utility properties exceeds their depreciated original cost. Therefore, a higher return could be justified. In this proceeding, Vectren South is proposing a rate mechanism to allow it to recover a return on its investment to accelerate the replacement of the oldest pipe in its system. This Project has many benefits as described by Witness James Francis, but does represent a cost to customers. In light of this request, which will also help Vectren South respond to the upcoming Distribution Integrity Rules, Vectren South has decided to not seek a higher return based on fair value rate base.

Q. Please summarize Vectren South Gas' request in this case?

A. Vectren South is requesting a revenue increase of about $10.4 million. This is less than 7% overall. Vectren South has clear need as recent actual returns on equity have been in the 2 to 4% range.

Vectren South has proposed, consistent with the Efficiency Settlement before the Commission, decoupled rates and the associated ROE test and fully expects to have implemented the efficiency programs described in that case before these rates are effective.

Vectren South has further proposed expenditures to address the aging workforce issue and a major new investment program to replace old pipe that is experiencing the highest leak rates.

Vectren South believes all of this is needed to serve customers well in the future and that the requested increase and ratemaking approaches are reasonable and needed to be able to attract capital at a reasonable cost going forward.

Q. Does this conclude your testimony?

A. Yes.

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH-GAS)

IURC CAUSE NO. 43112

DIRECT TESTIMONY
OF
M. SUSAN HARDWICK
VICE PRESIDENT, CONTROLLER AND ASSISTANT TREASURER

ON

REVENUE REQUIREMENT

SPONSORING PETITIONER'S EXHIBITS MSH-1-5

DIRECT TESTIMONY OF M. SUSAN HARDWICK

INTRODUCTION

Q. Please state your name and business address.

A. My name is M. Susan Hardwick. My business address is One Vectren Square, Evansville, Indiana 47708.

Q. By whom are you employed?

A. Vectren Corporation ("Vectren").

Q. What is your position with Southern Indiana Gas and Electric, Inc., d/b/a Vectren Energy Delivery, Inc. ("Vectren South" or the "Company")?

A. I am Vice President, Controller and Assistant Treasurer.

Q. What is your educational background?

A. I am a 1984 graduate of Indiana University with a Bachelor of Science Degree in Accounting. I am a Certified Public Accountant in the State of Indiana.

Q. Please describe your business experience.

A. From 1984 to 1992, I was employed by Arthur Andersen, LLP first as a staff auditor and ultimately promoted to Senior Manager. From 1992 to 1999, I was employed by PSI Energy, Inc. (PSI), and then Cinergy Corporation following the merger of PSI with The Cincinnati Gas and Electric Company, in various capacities, including Assistant Corporate Controller. Since 2000, I have served as Vice President and Controller of Vectren South and Vectren (Vectren South's ultimate parent company).

Q. What are your responsibilities as Vice President and Controller?

A. I am responsible for and oversee all accounting functions for Vectren South (and Vectren and its other utility subsidiaries), including financial, plant and tax accounting, budgeting, reporting and other functions.

Q. Are you familiar with the books, records, and accounting procedures of Vectren South?

A. Yes, I am.

Q. Are Vectren South's books and records maintained in accordance with the Uniform System of Accounts and generally accepted accounting principles?

A. Yes.

Q. Have you ever testified before any state regulatory commission?

A. Yes. I have testified before this Commission on behalf of Vectren South in Cause Nos. 41864 and 42861 involving Vectren South's clean coal technology projects. I have also testified before this Commission on behalf of Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana ("Vectren North") in Cause No. 42598 involving Vectren North's request for a base rate increase. I also testified before the Public Utilities Commission of Ohio on behalf of Vectren Energy Delivery of Ohio, Inc. ("Vectren Ohio") involving its request for a base rate increase. Vectren Corporation is also the parent company of both Vectren North and Vectren Ohio.

Q. Were your testimony and exhibits in this proceeding prepared by you or under your supervision?

A. Yes, they were.

PURPOSE

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the actual and pro forma cost of service for Vectren South gas operations and to present the components of its rate base, proposed rate of return and resulting required level of operating income. This information is presented in Petitioner's Exhibit MSH-2 and Petitioner's Exhibit MSH-3.

SUMMARY

Q. Please summarize your testimony.

A. Vectren South-Gas requires an increase in base rate revenues of $10,436,340, which will provide operating income of $9,431,041 based on pro forma test year results.

PRO FORMA REVENUE REQUIREMENT ANALYSIS

Q. Please refer to Petitioner's Exhibit MSH-2 and explain what it represents.

A. Petitioner's Exhibit MSH-2 is a statement of operating income for the 12 months ended March 31, 2006 (the test year for this proceeding), for Vectren South-Gas shown on an actual basis, pro forma basis and adjusted for the proposed increase in revenue. Column B shows the actual results for Vectren South-Gas for the 12 months ended March 31, 2006. Column C shows the pro forma adjustments made to reflect the going level of operations in order to reflect fixed, known and measurable changes which will occur within the 12 months following the test year. Column D shows the alphanumerical designations (e.g. A01, A02, etc.) used to identify each pro forma adjustment. These pro forma adjustments are described later in my testimony. Column E shows the pro forma statement of operating income reflecting the pro forma adjustments shown in Column C. Column F shows the pro forma adjustments required to produce Vectren South's proposed revenue requirement and operating income. Column G shows alphanumerical designations identifying the adjustments reflecting the proposed rate increase. These pro forma adjustments are also described more fully later in my testimony. Column H shows the pro forma statement of operating income after adjusting for the proposed rate increase.

Q. In your opinion, does Petitioner's Exhibit MSH-2, Column E, accurately reflect Vectren South-Gas' operating results during the test year, adjusted for fixed, known and measurable changes occurring during the 12 months after the end of the test year?

A. Yes.

Q. What are the actual operating results and the effect of the pro forma adjustments shown on this exhibit?

A. The actual operating income for the 12 months ended March 31, 2006, as shown on Column B, Line 64 of Petitioner's Exhibit MSH-2 is $5,385,194. The pro forma operating income at present rates shown on Column E, Line 64 is $3,371,759, as adjusted for the pro forma margin and operating expense adjustments shown in Column C. These pro forma adjustments are necessary to reflect on a full twelve-month basis fixed, known and measurable changes to actual test year results.

The proposed revenue increase is $10,436,340, required to provide a 7.96% return on net original cost rate base. This amount is shown on Column F, Line 1. The $10,436,340 revenue increase is required to produce the operating income of $9,431,041 as shown on Column H, Line 64 page 2.

PRO FORMA ADJUSTMENTS

Q. Please describe Petitioner's Exhibit MSH-3.

A. Petitioner's Exhibit MSH-3 includes the support for each pro forma adjustment and the proposed revenue increase. This exhibit includes 40 separate attachments labeled Adjustment A01 through Adjustment A40 that describe each pro forma adjustment at present rates.

Operating Revenue and Cost of Gas

Q. Please describe Adjustments A01 through A08 shown in Petitioner's Exhibit MSH-3.

A. Adjustments A01 through A08 are pro forma adjustments to Vectren South-Gas' test year gross margin and represent a net decrease in test year margin of $(243,005).

Q. Please describe these adjustments in detail.

A. Adjustment A01 represents an adjustment necessary to reflect the test year margin assuming normal weather. Normal weather was determined by reference to the 30 year normal degree days as published by NOAA. The test year actual margin was negatively impacted by weather that was 401 degree days, or 8.6% on an annualized basis, warmer than normal. The impact of this adjustment, revenue less cost of gas, is an increase in test year margin of $37,151. The net amount of this adjustment is reflective of the actual impact during the test year of the normal temperature adjustment mechanism in place at Vectren South.

Adjustment A02 represents an adjustment necessary to state test year revenues and cost of gas for 365 days of service. The actual test year results reflect 366.9 days of service. The test year incremental 1.9 days must be adjusted out of the test year. The adjustment reduces test year revenue net of cost of gas by $(17,680).

Adjustment A03 represents an adjustment needed to reflect the actual year end customer count on an annualized basis. The actual customer count at March 31, 2006 of 111,895 was used to calculate an annualized margin as if that level of customers were in place throughout the year. The adjustment was determined by calculating the difference between the test year beginning and ending actual customer count and assuming that the customers represented by that difference were ratably added or reduced throughout the test year. There were 125 fewer residential customers at March 31, 2006 as compared to March 31, 2005, 6 additional commercial class customers, and 41 fewer commercial class customers for the same period, therefore test year revenue net of cost of gas is reduced by $(8,376) to reflect the year end customer count impact.

Adjustment A04 represents the test year margin for certain large customers that are no longer on the system or have changed from a tariff customer to a transportation customer. Consolidated Grain has improved their production efficiency and has also secured an alternative fuel source. They have notified Vectren South that they will cancel their contract with Vectren South effective October 2006. Hoosier Magnetics has announced plant closure and will fully cease operation in 2007. General Electric Plastics is utilizing reverse osmosis which replaces traditional technology for water treatment processes. This then reduces their demand for natural gas. The combined impact from these customers is a reduction of 969,541 dekatherms, or $(292,808) of margin. Finally, AK Steel represents an offsetting test year increase in expected usage and revenue of $58,089. The net impact to the test year from all of these large customer changes is a reduction of $(234,719) in test year margin. As these are all transportation customers, there is no cost of gas impact.

Adjustment A05 represents the annualized impact on test year margin of customers that have migrated between customer classes during or subsequent to the test year. A single customer migrated from Rate 120 Sales to 120 Transportation, generating a $525 margin impact due to a $75 higher service/transportation charge. Thirteen residential customers were also migrated to Rate 120 Sales because their business category indicated they should be on a non-residential rate schedule. This results in an increase in margin of $1,177 due to the increased service charge, slightly offset by lower step rate pricing. Net, the impact of customer migration on the test year is an increase in test year revenue of $1,702.

Adjustment A06 represents the removal of the change in unbilled revenue recorded in the test year of $456,911 as the revenues and cost of gas presented herein reflect a billed basis rather than an unbilled basis.

Adjustment A07 reflects an adjustment of $110,866 to reflect the expected level of Pipeline Safety Act costs that will be recovered during the pro forma year under the Pipeline Safety Adjustment (PSA) tracker. This amount includes the IURT impact. There is a similar adjustment, Adjustment A18, that reflects an increase in Pipeline Safety Act costs to be incurred in the test year that will recovered through the Tracker. Both entries simply "normalize" the test year amount to reflect full allowed recovery under the Tracker cap.

Adjustment A08 represents an adjustment to reflect the current expected cost of gas per dekatherm of $10.20. The reduction from the test year of $10.24 per dekatherm at the test year level of volumes results in the adjustment. This adjustment is reflected in both revenues and cost of gas, with no net impact on margin, except for the impact of the Indiana Utility Receipts Tax on the lower cost of gas and other impacts in the test year.

Because of the volatile nature of gas costs, fixing the recovery of the cost of unaccounted for gas in base rates is not appropriate. Vectren South proposes that the actual cost of unaccounted for gas that varies from the base cost of gas established in this proceeding be recovered through the GCA mechanism. Vectren South Witness Scott E. Albertson discusses this proposal in more detail.

The majority of the adjustments discussed above (A01-A08) reflect both a revenue and cost of gas component. The net impact of all of these adjustments, as noted above, is a reduction in test year margin of $(243,005).

Operations and Maintenance Expense

<u>Labor and Labor Related Costs:</u>

Q. Please describe Adjustment A09 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A09 represents an adjustment to pro forma labor costs. Test year labor expense was $6,668,752 and the pro forma level is $6,812,507, which results in Adjustment A09, an increase of $143,755. The adjustment is calculated based on the actual number of employees (filled positions) as of March 31, 2006 and the level of wage increases, fringe benefits and payroll taxes expected to be in effect for the twelve months subsequent to the test year. This adjustment includes the annualization of a 3.5% wage increase to union employees (IBEW, Teamsters) effective July 1, 2006 and September 24, 2006, respectively. The wage rates as of March 31, 2006 for non-union employees, escalated at 3.5%, were used in the calculation of the pro forma adjustment. The 3.5% increase is the amount of the budgeted non-union salary increase for 2007 that will go into effect March 1, 2007. The portion of the adjustment attributable to wage increases is approximately $260,000.

The fringe benefit (healthcare, 401K, and other costs) loading rates and payroll tax rates based on 2006 budgeted costs and expected to be in effect for the twelve months subsequent to the test year were used to determine the pro forma level of benefit expenses. A cost allocation, or "loading", process is used to distribute benefit costs based on direct labor charges. The portion of the adjustment related to increased wages and benefit costs is approximately $157,000.

The remaining portion of the adjustment, or $(273,245), is attributable to changes to cost allocations, primarily between the gas and electric divisions of Vectren South, offset by the annualized wage and benefit costs of employees added during the test year.

Q. Please describe the cost allocation factors and related process in effect during the test year.

A. Cost allocation factors are used to distribute common administrative, supervision and certain other costs to the appropriate entities within Vectren Corporation. Allocation factors appropriate for each type of cost, such as number of customers, number of employees, operating margin, capital expenditures, etc., are used to derive weighted percentages that are then applied to costs incurred that are relevant to the factor. As an example, customer service costs are allocated to the various utility companies based on the number of customers served by each utility.

The methodology and development of the allocation factors used in the test year and currently in effect have been reviewed by the Company's independent auditor, Deloitte & Touche, LLP ("Deloitte"), and were found to be appropriate, reasonable and consistent with industry practice. Where applicable, these cost allocation factors have been applied in the calculation of the remaining pro forma adjustments described throughout the remainder of my testimony. The allocation percentages for the more significant allocators currently in place for Vectren South-Gas are as follows:

- If costs are allocated based on number of employees, the allocation percentage for Vectren South-Gas is just over 10% (10.5%). For example, this allocation percentage would apply to all labor-related costs as shown in Adjustments A10-A11 discussed below.
- If costs are allocated based on number of customers, the allocation percentage for Vectren South-Gas is just under 9% (8.55%). For example,

this allocation applies to customer credit and collection and billing costs as shown in Adjustments A20-A24 discussed below.

- If costs are allocated based on a weighting of margin, capital expenditures, and payroll, the allocation percentage for Vectren South-Gas is 11%. For example, this allocation applies to certain risk insurance expense as shown in Adjustment A28 discussed below.
- If costs are allocated using an equal weighting of total customers and total employees, the allocation percentage to Vectren South-Gas is about 9%. For example, this allocation is used to allocate costs of shared assets like computer systems and buildings as shown in Adjustment A35 discussed below.

Q. Please describe Adjustments A10 and A11 shown in Petitioner's Exhibit MSH-3.

A. Adjustments A10 and A11 represent adjustments to reflect the proper level of compensation costs, other than direct salary, in the test year. As key elements of its total compensation program, Vectren uses a combination of base salary, long term incentive compensation (restricted stock and stock options) and annual (or short term) incentive compensation. The total compensation program is reviewed regularly by Vectren's Board of Directors in order to determine the appropriate combination and levels of such compensation elements, as well as setting performance standards and approval of payout levels. The direct salary adjustment was included in the previously described labor cost adjustment. Adjustments A10 and A11 adjust the amount of long term and short term incentive compensation, respectively, based on current targets.

Q. Please explain how the long term incentive compensation adjustment was derived.

A. Page 2 of Adjustment A10 shows the derivation of the appropriate level of restricted stock and stock option expense that will be incurred by Vectren South-Gas based on the number of restricted shares that are currently outstanding including the number of restricted shares granted effective January 1, 2006 and an assumed share price of $28.52, which represents 5% growth from the 2005 year end stock price. The calculated expense amount is compared to the actual amount in the test year, resulting in a difference related to restricted stock of $196,325. In the test year, Vectren South-Gas expensed $9,279 associated with employee stock options based on the Financial Accounting Standards Board (FASB) standard that was effective January 1, 2006. Vectren does not intend to issue stock options in the future and therefore this cost has been removed from Vectren South Gas' cost of service. Also, resulting from the new FASB standard, Vectren began expensing the dividends paid on restricted stock. Combined, the adjustment to reflect the proper level of long term incentive compensation of $419,919, compared to the test year level of $232,874, is an increase in operating cost of $187,046.

Q. Please explain the adjustment for annual (short term) incentive compensation shown in Adjustment A11.

A. Adjustment A11 reflects the appropriate level of short term annual incentive compensation that will be incurred by Vectren South-Gas based on the incentive plan targets that have been approved by Vectren's Board of Directors for 2006. The annual incentive plan is based on a weighting of performance measures such as earnings, safety, and customer satisfaction. The adjustment amount of $17,518 is determined by comparing the calculated amount of $443,936, which represents targeted performance, to the amount in the test year of $426,418. Further discussion of incentive compensation is included in the testimony of Vectren South-Gas Witness Jerome A. Benkert, Jr.

Q. Please describe Adjustments A12 and A13 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A12 is an adjustment to reflect the pro forma pension expense determined pursuant to FASB's Statement of Financial Accounting Standards No. 87 ("FAS 87"), and Adjustment A13 is an adjustment to reflect the expense of pro forma post retirement benefits other than pensions determined pursuant to FASB's Statement of Financial Accounting Standards No. 106 ("FAS 106") on an accrual basis. The test year amount for pension expense was $517,563. The pro forma increase in pension expense is $47,152 resulting in a pro-forma expense of $564,804. As shown in Adjustment A13, the test year expense for post retirement benefits other than pensions was $224,261. The pro forma expense is $154,608, resulting in a pro forma decrease in post retirement expenses of $(69,653). The annual level of pension and post retirement benefits expense was determined by the Company's actuary, Towers Perrin, based on actuarial calculations using current census data and actuarial assumptions, as reviewed and approved by Vectren's Investment Committee, and as reflected in the 2005 Plan Year actuarial valuations. The pro forma level of expense is determined consistent with FAS 87 and FAS 106 as reflected in the GAAP financial statements.

Q. Please describe Adjustment A14 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A14 represents an adjustment to additional participation in various training programs including certain refresher safety training and emergency preparedness and disaster programs for distribution operations personnel. The impact of this adjustment is to increase training costs in the amount of $37,088 and is discussed further by Vectren South Witness William S. Doty.

Q. Please describe Adjustment A15 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A15 represents an adjustment to reflect incremental headcount added or expected to be added since the end of the test year. The incremental headcount consists of 24 positions. All of the positions are approved and the majority have been filled, or are expected to filled, during the pro forma period. After the appropriate allocation of costs to Vectren South-Gas, the portion of the adjustment attributable to wages for the positions totals $134,421. The remainder of the adjustment represents the fringe benefits and payroll taxes related to those positions. The portion of the adjustment attributable to benefit costs is $79,511. The total pro forma adjustment is $213,932. The positions that are operations-related are discussed in detail by Vectren South Witness William S. Doty. The remaining eight positions are detailed on lines 1-6 of Adjustment 15 page 2 of 2 and are shared service, or A&G, type positions.

<u>Aging Workforce Related Costs:</u>

Q. Please describe Adjustment A16 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A16 reflects $430,411 in additional expense on a pro forma basis that will be incurred by Vectren South-Gas related to its aging workforce. Vectren South Witness William S. Doty supports this issue in substance and addresses the adjustment as it affects gas operations.

<u>Operation and Maintenance Programs:</u>

Q. Please describe Adjustment A17 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A17 represents the removal of test year costs incurred related to Vectren South-Gas' former manufactured gas plant sites. The costs incurred in the test year relate to legal and certain study costs in the preliminary evaluation of the sites. Vectren South-Gas is not seeking recovery of those costs.

Q. Please describe Adjustment A18 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A18 reflects additional costs over the test year amount that will be incurred and recovered through the PSA tracker during the pro forma period. See the related revenue entry at Adjustment A07. The net impact of these two entries on net operating income is zero, except for the IURT impact on revenue.

Q. Please describe Adjustment A19 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A19 reflects an increase in distribution maintenance expense of $636,600. This expense will be incurred to conduct maintenance activities at regulator stations and to maintain cathodic protection on gas casings and pipelines and increased levels of right of way clearance. Vectren South-Gas Witness William S. Doty provides additional support for this adjustment.

Q. Please describe Adjustment A20 shown in Petitioner's Exhibit MSH-3.

A. The pro forma level of bad debt (uncollectible accounts) expense was determined by applying the five year average of actual write-offs experienced by Vectren South-Gas of .74% of revenues to pro forma revenues of $155,034,212 as calculated in Adjustment A20. The five years of actual write-off experience used were the twelve month periods ending March 2002, 2003, 2004, and 2005, and the test year. Similarly, actual revenues for the same period were used in the calculation, along with pro forma revenues for the test year. This calculation resulted in a pro forma level of bad debt expense of $1,147,253 compared to the test year amount of $342,271, or an increase in expense of $804,982. Because this particular expense is so related to gas costs, a five year average was used to reflect some of the volatility in gas costs over a longer time period.

Because of the continued volatility of natural gas prices and the resulting impact on customers' ability to pay, Vectren South proposes that the gas cost commodity portion of bad debts to the extent it varies from the amount set in base rates in this proceeding be recovered through the GCA mechanism. Use of the GCA recovery mechanism serves the interests of the company in addressing costs that fluctuate from year to year largely outside of its control, and the interests of customers given that it is equally possible that this cost will decline if gas prices decline. The rationale and mechanism proposed is more fully described by Vectren South-Gas Witness Robert C. Sears.

Q. Please describe Adjustment A21 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A21 reflects an increase in annual meter reading expense of $26,001. Of that increase, $24,501 is attributable to an increase in the contract cost of meter reading of 1.5¢ per meter and approximately 2% growth in the number of meter reads. As described in the testimony of Vectren South-Gas Witness William S. Doty, Vectren South avoided a much larger increase in contract meter reading cost by securing the services of two new contract meter reading companies. The balance of the adjustment, $1,500, is to provide incentives to all our meter readers to detect and report instances of gas diversion and non-registering meters. Additional support for this necessary adjustment is provided by Vectren South-Gas Witness William S. Doty.

Q. Please describe Adjustment A22 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A22 reflects Vectren South-Gas' share of the increased annual cost for additional customer service representatives and other customer service costs at the contact center in Evansville. Additional call center representatives, both employees and contractors, are necessary to handle the higher levels of calls stemming from higher gas costs, increased interest in budget billing, inquiries regarding payment plans financial assistance and disconnection notices. Vectren South-Gas Witness William S. Doty provides additional support for this adjustment totaling $118,466.

Q. Please describe Adjustment A23 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A23 in the amount of $71,735 represents Vectren South-Gas' increased annual cost in the areas of economic development and marketing research. The overall intent of this additional cost is to provide strategic focus on growing economic development opportunities and in increasing customer satisfaction through more direct communication and exchange with our customer base, particularly commercial and industrial customers. Additional detailed support for this adjustment is provided in the testimony of Vectren South-Gas Witness Ronald B. Keeping.

Q. Please describe Adjustment A24 shown in Petitioner's Exhibit MSH-3.

A. Vectren South out-sources its bill processing and mailing function. Adjustment A24 represents the pro forma level of costs to be paid for postage. The adjustment amount of $15,627 was calculated by applying the 5.4% postage increase which was effective January 1, 2006 to the test year postage costs, plus miscellaneous billings expenses.

Q. Please describe Adjustment A25 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A25 represents an adjustment to increase test year expenses for various information technology contractual obligations and estimated costs for software fees, hardware maintenance and telecommunications fees and taxes. This adjustment is an increase of $89,346 in test year information technology costs as allocated to Vectren South-Gas. The adjustment also reflects an offsetting reduction to remove the duplicate costs for contractors that have been eliminated during the test year. The help desk administration and staffing was brought in house effective April 1, 2005, thus reducing test year expenses in the amount of $(13,205) as allocated to Vectren South-Gas. The net impact of this adjustment is an increase in information technology costs of $76,141 in pro forma expenses.

Amortization of Deferrals:

Q. Please describe Adjustment A26 that is shown in Petitioner's Exhibit MSH-3.

A. Adjustment A26 represents an adjustment to increase test year expenses for the estimated incremental rate case costs associated with this proceeding. Line 1 of page 2 reflects the total estimated cost of the current proceeding. Line 2 reflects the estimated unamortized costs from Cause No. 42596. Line 3 is the sum of the total rate case costs to be amortized. Vectren South-Gas proposes a three year amortization of the rate case costs. Line 5 reflects the pro forma costs amortized over the three-year period. The pro forma adjustment of $43,615 shown on Line 3 of page 1 represents the annual amortization of the estimated expenses of $245,418 less the test year amount of amortization from the prior case of $201,803.

Q. Please describe Adjustment A27 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A27 is an adjustment to reflect the amortization of the expected deferred costs as of March 31, 2007 related to costs incurred related to the requirements of the Pipeline Safety Improvement Act of 2002. In accordance with the Commission order in Cause No 42596, Vectren South-Gas has in place a recovery mechanism, the PSA tracker, for the periodic recovery of such costs. The annual recovery of such costs is capped at $500,000 currently, with no carrying costs. The costs incurred to date have exceeded the cap and as a result a deferred balance has accumulated. Further it is expected that the deferral will continue to grow. This adjustment proposes that the estimated deferred balance of $1,595,657 as of March 31, 2007 be amortized over a three year period. At the effective date of new rates, if the deferred balance differs from the pro forma amount included in base rates, it is proposed that the difference be included in the PSA tracker going forward. Because of the relative newness of this effort and the variability in the annual cost, the existing PSA tracker mechanism should remain in place. The details of the pipeline safety program are further discussed by Vectren South-Gas Witness James Francis. Vectren South-Gas Witness Scott E. Albertson further discusses the ongoing Pipeline Safety Adjustment approved in Cause No 42596.

<u>Other Costs/Adjustments:</u>

Q. Please describe Adjustment A28 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A28 is an adjustment to reflect the level of property insurance expense related to its utility property at the end of the test year. Included in the adjustment is a decrease in property insurance expense for the test year of $(155,702). The pro forma property insurance expense reflects current premiums for Vectren South insurance coverage for its gas utility property.

The adjustment also reflects the pro forma level of risk insurance expense. The pro forma risk insurance expense reflects current premiums for insurance covering workers compensation, automobile liability, and corporate liability. The pro forma adjustment resulted in an increase in risk insurance expenses of $43,597. Combined, the adjustment to reflect the appropriate pro forma level of property and risk insurance of $535,520 is a decrease in expense of $(112,105) from a test year level of $647,625. The decrease in expense results primarily from a change in the method of allocating above ground property insurance costs subsequent to the end of the test year.

Q. Please describe Adjustment A29 shown in Petitioner's Exhibit MSH-3.

A. Vectren South is self-insured for a portion of its injury and damage claims (i.e. Vectren insurance policies have a deductible of $1.0 million per occurrence). The pro forma level of claims expense of $582,181 is based on a three year average of actual claims paid experience and a three year "amortization" of a single major claim that was expensed (but not yet paid) in the test year. The pro forma level is compared to the test year amount of $556,793, resulting in an increase in claims expense of $25,388.

Q. Please describe Adjustment A30 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A30 reflects the reduction in test year expenses related to the former Vectren corporate headquarters in Evansville. That facility was vacated in 2005 with the move to the new headquarters location at One Vectren Square. This amount represents the lease and other operating costs related to the former headquarters facility incurred in the test year as allocated to Vectren South.

Q. Please explain Adjustment A31 shown in Petitioner's Exhibit MSH-3.

A. The purpose of an allocation factor is to allocate costs in a manner that best represents cost causation. During the annual budgeting process, cost center allocation factors and the level of administrative and general costs subject to capitalization are reviewed for appropriateness and are adjusted as needed. Adjustment A31 reduces test year expenses by $(153,983) for costs in cost centers for which the allocation factor changed during the 2006 budget process and to reflect increased capital costs.

Also in analyzing test year operating costs, it was determined that $181,994 of costs in outside services and certain other expenses were charged in error to other Vectren entities instead of Vectren South-Gas. Adjustment A31 adds this amount to Vectren South-Gas' operating expenses. The sum of these items represents an increase in test year expenses of $28,011.

Q. Please describe Adjustment A32 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A32 reflects costs to be incurred to facilitate programs initiated by the Asset Management Transformation (AMT) project, an internal team focused on streamlining the energy delivery asset management process. Vectren South-Gas Witness William S. Doty discusses the initiative in further detail in his direct testimony.

Q. Please describe Adjustment A33 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A33 reflects an incremental reduction in test year expenses of $(18,599) as a result of savings expected to be realized from the AMT project during the pro forma period. Vectren South-Gas Witness William S. Doty discusses the initiative in further detail in his direct testimony.

Q. Please describe Adjustment A34 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A34 reflects the pro forma level of Indiana Utility Regulatory Commission (IURC) Fees and is determined by applying a rate of 0.11% to the pro forma level of revenues for the test year. The pro forma revenue includes pro forma margins shown on Petitioner's Exhibit MSH-2 plus pro forma gas costs. The pro forma increase of $100,932 was calculated as the difference between the pro forma level of IURC fees and the test year amount.

Q. Please describe Adjustment A35 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A35 reflects a pro forma increase in Vectren Utility Holdings' (VUHI) (a Vectren subsidiary) asset charges for the test year. VUHI owns certain information technology assets and buildings and charges each of the Vectren utility and non-utility operations, including Vectren South, for amounts reflecting their respective use of those assets. The asset charge covers the carrying costs on property and equipment recorded on VUHI's books. The asset charge includes depreciation expense, property taxes, and a fair and reasonable return on net plant. Line 1 of page 1 of Adjustment A35 shows the gross plant for VUHI at March 31, 2006. Line 3 shows the net plant determined by subtracting accumulated depreciation from gross plant. The return and income taxes shown on Line 5 is calculated by applying the Vectren South cost of capital (as calculated in this proceeding) grossed up for income taxes to the net plant shown on Line 3. The calculation of the weighted cost of capital grossed up for income taxes is shown on Page 2 of Adjustment A35. Depreciation expense of $21,148,656 is shown on Line 6 of Adjustment A35 and represents annualized depreciation expense on the assets as of March 31, 2006. Property tax expense of $1,069,000 is shown on Line 7 and represents annualized property tax expense on the assets as of March 31, 2006. The pro forma asset charge attributable to Vectren South-Gas operations is $3,475,132. The pro forma adjustment results in an increase of $168,475 that is shown on Line 12 of page 1 and is determined by calculating the difference between the pro forma level of asset charges attributable to Vectren South-Gas operations and the amount reflected in the test year.

Q. How are these asset costs charged to Vectren's various entities?

A. The three largest assets shared among Vectren's operating entities are its customer billing system, call center, and corporate headquarters. The costs allocated to each entity have been calculated independently for these assets. Costs for the customer billing system and the call center are allocated only to the utilities using a blended rate of utility customers and utility full time equivalent employees. The corporate headquarters is allocated between regulated utilities and nonregulated operations using square footage. The utility-related costs are then allocated to each of the operating utilities using a blended rate of each utility's customers and each utility's employees.

Q. Why is the charge for the use of these assets shown as a separate component in the determination of Vectren South's net operating income?

A. The assets owned by VUHI are shared among Vectren's operations and are used predominantly by the utility operations. Because the functions performed by these assets are common to the utilities (i.e. customer billing systems, financial systems, buildings, etc.), it is more efficient to have them centrally owned and operated. Without this sharing, each utility company would own its own such assets and include the costs in its rate base with a fair return thereon required. The centralized ownership certainly provides the opportunity for economies of scale. The amounts charged to each utility mirror the treatment that would be achieved if the assets were in rate base by charging a return of and on the investment, as well as operating costs like property taxes. The amount charged is shown on the financial statements as an operating expense, akin to a lease or rental charge.

<u>Depreciation Expense, Taxes Other than Income, and Income Taxes:</u>

Q. Please describe Adjustment A36 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A36 reflects the pro forma adjustment to depreciation expense. The pro forma level of depreciation expense shown on Line 1 of $5,544,105 is based on utility plant balances as of March 31, 2006 by primary account and the applicable depreciation rates currently in effect and in effect since the last

Vectren South gas base rate proceeding. The pro forma increase in depreciation expense of $192,508 from a test year level of $5,351,597 is shown on line 3. A depreciation study was not performed in this case as the current rates are believed to be appropriate as there have been no significant additions or retirement of assets, no significant changes in the operation of the assets, or the lives of assets in service since the prior study.

Q. Please describe Adjustments A37, A38, and A39 that are shown in Petitioner's Exhibit MSH-3.

A. Adjustments A37 and A38 show the pro forma state and Federal income tax expense reflecting all pro forma adjustments shown on Column C of Petitioner's Exhibit MSH-2. These calculations also reflect synchronized interest of $2,855,378 as calculated on page 3 of Adjustment A41.

These pro forma entries result in a combined Federal and state effective tax rate of 37.26%.

Adjustment A39 shows the pro forma increase in Utility Receipts Tax. The adjustment reflects the Utility Receipts Tax of 1.4%.

Q. Please describe Adjustment A40 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A40 is an adjustment to reflect the pro forma level of property tax expense related to Vectren South-Gas property. The pro forma level was determined by multiplying the 2006 taxes paid by the three year average annual increase in property tax rates and assessed value. The pro forma adjustment is a decrease in expense of $(112,887), which is the difference between the pro forma level of $902,729 and the test year amount of $1,015,616.

PROPOSED REVENUE INCREASE

Q. Please describe Adjustment A41 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A41 shows the calculation of the increased revenue requirement for Vectren South-Gas necessary to provide a 7.96% return on net original cost rate base of $118,480,432. The 7.96% rate of return on page 3 of Adjustment A41 is supported in the testimony of Vectren South-Gas Witness Robert L. Goocher. The increased revenue requirement is calculated by determining the required increase in operating income. The required operating income is determined by applying the proposed rate of return of 7.96% to the net original cost rate base for Vectren South-Gas shown on page 2 of Adjustment A41. The increase in operating income is then grossed up for the following taxes and fees: (a) Federal income taxes, (b) State income taxes, (c) Utility Receipts taxes, and (d) IURC Fees. The total proposed increase in revenue requirements to provide a 7.96% return on net original cost rate base is $10,436,340.

Q. How was the original cost rate base determined, as shown on page 2 of 3 of Adjustment A41 shown in Petitioner's Exhibit MSH-3?

A. The original cost rate base of $118,480,432 shown on page 2 of 3 of Adjustment A41 represents the plant in service balance per the Company's books and records as of March 31, 2006 less the accumulated depreciation reserve as of the same date plus the thirteen month average of the book balances of materials and supplies, stores expense, and gas in underground storage.

Q. Please describe Adjustment A42 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A42 reflects the additional uncollectible accounts expense on the revenue increase requested using the five year average actual write-offs as a percentage of revenue, for an increase in expense of $77,229 at the proposed rates level.

Q. Please describe Adjustment A43 shown in Petitioner's Exhibit MSH-3.

A. Adjustment A43 reflects the IURC fee on the requested revenue increase at .11%, or $11,480.

Q. Please describe Adjustments A44, A45, and A46 that are shown in Petitioner's Exhibit MSH-3.

A. Adjustments A44 and A45 are calculations of the income taxes applicable to the proposed increase in revenue requirements for Vectren South-Gas operations, and are calculated by applying the 35.0% federal income tax rate and the 8.5%

state income tax rate to the proposed increase. Although the impact reflects only the incremental tax effects, the calculation is performed showing a complete state and federal income tax calculation.

Adjustment A46 is a calculation of the Indiana Utility Receipts Tax applicable to the proposed increase in revenue requirements for Vectren South-Gas operations and is calculated by applying the 1.4% rate to the proposed increase.

Q. Please describe Petitioner's Exhibit MSH-4.

A. Petitioner's Exhibit MSH-4 is a summary by FERC account that reflects the posting of the pro forma adjustments discussed above by account. This was prepared to aid in the review of the entries and their impact on each account.

Q. Please describe Petitioner's Exhibit MSH-5.

A. This exhibit contains Vectren South-Gas' Comparative Financial Statements for the periods ended March 31, 2006 and 2005, as required by the Commission's Minimum Standard Filing Requirements.

<u>SUMMARY</u>

Q. Please summarize your testimony.

A. As shown in Column F of Petitioner's Exhibit MSH-2, Vectren South-Gas is proposing an increase in revenue of $10,436,430, which will provide an operating income of $9,431,041, based on pro forma results for the test year. This operating income produces a return on original cost rate base of 7.96%.

Q. Does this conclude your testimony?

A. Yes.

VECTREN SOUTH
GAS TARIFF
ACTUAL AND PRO FORMA STATEMENT OF OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Line No.	Description	Actual Per Books	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
	Operating Revenues							
1	Gas Revenue	$ 148,992,417			$ 155,034,212	10,436,340	A41	165,470,552
2	Normal Weather		$ 7,376,767	A01				
3	Annualized Days of Service		$ (171,184)	A02				
4	Customer Count		$ (129,238)	A03				
5	Large Customer Changes		$ (234,719)	A04				
6	Customer Migration		$ 1,702	A05				
7	Unbilled Revenue		$ 456,911	A06				
8	Pipeline Safety Act Cost Recovery		$ 110,866	A07				
9	Cost of Gas		$ (1,369,310)	A08				
10								
11	Total	$ 148,992,417	$ 6,041,795		$ 155,034,212	10,436,340		165,470,552
12	**Cost of Gas**	112,708,759			$ 118,993,559			118,993,559
13	Normal Weather		$ 7,339,616	A01				
14	Annualized Days of Service		$ (153,504)	A02				
15	Customer Count		$ (120,862)	A03				
16	Cost of Gas		$ (780,450)	A08				
17								
18		112,708,759	6,284,800		118,993,559	-		118,993,559
19	Gross Margin	$ 36,283,658	$ (243,005)		$ 36,040,653	$ 10,436,340		$ 46,476,993
	Operation and Maintenance Expenses							
20	Operations and Maintenance Expenses	$ 16,778,238			$ 19,971,906			20,060,614
21	**Labor and Labor Related Costs**							
22	Labor Adjustments for Existing Headcount		$ 143,755	A09				
23	Labor-Related Costs		$ 187,046	A10				
24	Other Compensation		$ 17,518	A11				
25	Pension Expense		$ 47,152	A12				
26	Postretirement Medical Expense		$ (69,653)	A13				
27	Training Expense		$ 37,088	A14				
28	Additional Employees		$ 213,932	A15				
29	**Aging Workforce Related Costs**							
30	Aging Workforce		$ 430,411	A16				
31	**Operation and Maintenance Programs**							
32	Manufactured Gas Plant Expense		$ (316,500)	A17				
33	Pipeline Safety Act Costs		$ 109,335	A18				
34	Distribution Maintenance		$ 636,600	A19				
35	Uncollectible Accounts Expense		$ 804,982	A20				
36	Meter Reading Costs		$ 26,001	A21				
37	Contact Center Costs		$ 118,466	A22				
38	Sales and Marketing Costs		$ 71,735	A23				
39	Miscellaneous Billing Costs		$ 15,627	A24				
40	Information Technology Costs		$ 76,141	A25				
41	**Amortization of Deferrals**							
42	Rate Case Expense		$ 43,615	A26				
43	Pipeline Safety Act Costs Amortization		$ 531,886	A27				
44	**Other Costs/Adjustments**							
45	Property and Risk Insurance		$ (112,105)	A28				
46	Claims Expense		$ 25,388	A29				
47	Other Cost Reductions		$ (33,227)	A30				
48	Changes in Cost Allocations		$ 28,011	A31				
49	Asset Management Program Costs		$ 78,131	A32				
50	Asset Management Program Savings		$ (18,599)	A33				
51	Pro Forma Level Uncollectible Accounts					77,229	A42	
52	IURC Fee		$ 100,932	A34		11,480	A43	
53								
54		$ 16,778,238	$ 3,193,668		$ 19,971,906	88,709		20,060,614
55	Asset Charge	3,306,657	$ 168,475	A35	$ 3,475,132			3,475,132
56	Total Operations and Maintenance	$ 20,084,895	$ 3,362,143		$ 23,447,038	$ 88,709		$ 23,535,747

VECTREN SOUTH
GAS TARIFF
ACTUAL AND PRO FORMA STATEMENT OF OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Line No.	Description	Actual Per Books	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
57	Depreciation and Amortization	$ 5,351,597	$ 192,508	A36	$ 5,544,105			5,544,105
	Taxes							
58	Income Taxes (Federal and State)	$ 2,417,982	$ (752,955)	A37	$ 620,612	879,549	A44	4,762,852
59			$ (1,044,415)	A38		3,262,691	A45	
60	Other Taxes (IURT and Property Tax)	3,043,990	$ 126,036	A39	$ 3,057,139	146,109	A46	3,203,248
61			$ (112,887)	A40				
62	Total Taxes	$ 5,461,972	$ (1,784,221)		$ 3,677,751	4,288,349		7,966,100
63	Total Operating Expenses	$ 30,898,464	$ 1,770,430		$ 32,668,894	$ 4,377,058		$ 37,045,952
64	Net Operating Income	$ 5,385,194	$ (2,013,435)		$ 3,371,759	6,059,282		9,431,041

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Normal Weather

Line No.	Category		
1	Revenue	$	7,376,767
2	Less: Cost of Gas		7,339,616
3	Pro Forma Margin Adjustment to Reflect Normal Weather	$	37,151

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Normal Weather Pro Forma Adjustment

Line No.		Total Therms	Non-Temp Sales & Trans. (Jul - Aug)	Non-Temp Sales & Trans. Full Year	Temp Sensitive Sales & Trans.	Actual Degree Days	Therms per Degree Day	Normal Degree Days	Departure From Normal	Normal Temp Adjustment	Net Margin Per Therm Sold	Net Margin Adjustment	Cost of Gas Per Therm Sold	Gas Cost Adjustment
1	**Rate 110**	69,961,192	2,547,629	15,285,774	54,675,418	4,255	12,848	4,656	401	5,152,206	$ 0.1187	$ 611,743	$ 1.0195	$ 5,252,591
2	**Rate 120 Sales**	35,490,613	2,294,382	13,766,292	21,724,321	4,255	5,105	4,656	401	2,047,139	0.0815	$ 166,842	1.0195	$ 2,087,025
3	**Total**	105,451,805	4,842,011	29,052,066	76,399,739					**7,199,345**		**$ 778,585**		**$ 7,339,616**
4						**Billed NTA Revenue**				-		**$ 741,434**		-
5						**Total Temperature Adjustment**				**7,199,345**		**$ 37,151**		**$ 7,339,616**
6											R110	$ 62,795		
7											R120	(25,644)		
8											Total	$ 37,151		

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Annualized Days of Service

Line No.	Category		
1	Revenue	$	(171,184)
2	Less: Cost of Gas		(153,504)
3	Pro Forma Margin Adjustment to Reflect Annualized Days of Service	$	(17,680)

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE MONTH TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Annualized Days of Service Pro Forma Adjustment

Line No.		Non-Temp Sales & Trans. (Jul - Aug)	Baseload Days of Service	Baseload per Day	Actual Days of Service	Normal Days of Service	Departure From Normal	Baseload Adjustment	Margin Per Therm Sold	Net Margin Adjustment	Cost of Gas Per Therm Sold	Gas Cost Adjustment
1	**Rate 110**	2,547,629	61.1	41,696	366.9	365.0	(1.9)	(79,223)	$ 0.1391	$ (11,023)	$ 1.019	$ (80,766)
2	**Rate 120 Sales**	2,294,382	61.1	37,551	366.9	365.0	(1.9)	(71,347)	$ 0.0933	$ (6,657)	$ 1.019	$ (72,738)
3	**Total**	4,842,011	61.1	79,247	366.9	365.0	(1.9)	(150,570)		(17,680)		**(153,504)**
4						**Total Days of Service Adjustment**		(150,570)				
5								Margin impact		$ (17,680)		
6								Cost of Gas				**$ (153,504)**
7								Revenue				**$ (171,184)**

Petitioner's Exhibit No. MSH-3
Adjustment A02
Page 2 of 2

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Customer Count

Line No.	Category		
1	Revenue	$	(129,238)
2	Less: Fuel Cost		(120,862)
3	Pro Forma Margin Adjustment to Reflect Customer Count	$	(8,376)

Petitioner's Exhibit No. MSH-3
Adjustment A03

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Customer Count Pro Forma Adjustment

Line No.		Rate 110		Rate 120			Rate 120 (Transport)		
1	Customers 3/31/06	101,461		10,356			78		
2	Customers 3/31/05	101,586		10,397			72		
3	Customer Growth		(125)		(41)			6	
4	Customers 3/31/06	101,461		10,356			78		
5	Customers 3/31/05	101,586		10,397			72		
6	Average Number of Customers		101,524		10,377			75	
7	Percent Customer Growth		-0.12%		-0.40%			8.00%	
8	Therms		74,982,104		40,672,563			4,824,168	
9	Annual Therms		(92,321)		(160,707)			385,933	
10	To reflect additions throughout the year		50%		50%			50%	
11	Incremental volumes		(46,161)		(80,353)			192,967	
12	Volumetric margin per unit		$ 0.1231		$ 0.0910			$ 0.0824	
13	Volumetric margin		(5,681)		(7,315)			15,897	
14	Group I, II and III spread			70%	24%	6%			
15	Customer Growth		(125)	(29)	(10)	(2)		6	
16	Months in a year		12	12	12	13		12	
17	Additional Bills		(1,500)	(348)	(120)	(26)		72	
18	To reflect additions throughout the year		50%	50%	50%	150%		50%	
19	Estimated number of bills		(756)	(180)	(60)	(39)		36	
20	Service Charge per month		$ 10.75	$ 20.00	$ 34.00	$ 70.00		$ 145.00	
21	Service Charge Revenue per month		(8,127)	(3,600)	(2,040)	(2,730)		5,220	
22	Margin (13 + 21)		$ (13,808)		$ (15,685)			$ 21,117	$ (8,376)
23								Cost of Gas	$ (120,862)
24								Revenue	$ (129,238)

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Large Customer Changes

Line No.	Category		
1	Test Year Revenue	$	4,917,668
2	Pro Forma Revenue		4,682,949
3	Pro Forma Margin Adjustment to Reflect Large Customer Changes	$	(234,719)

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Customer Migration

Line No.	Category	
1	Pro Forma Margin Adjustment to Reflect Customer Migration	$ 1,702

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Remove Test Year Unbilled Revenue

Line No.	Category	
1	Adjustment to Remove the Change in Test Year Unbilled Revenue	$ 456,911

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pipeline Safety Act Cost Recovery

Line No.	Category		
1	Pro Forma Pipeline Safety Act Cost Recovery	$	500,000
2	Less: Test Year Pipeline Safety Act Cost Recovery		390,665
3	Increase in Pipeline Safety Act Cost Recovery		109,335
4	Add: Increase in IURT		1,531
5	Pro Forma Increase in Pipeline Safety Act Cost Recovery	$	110,866

Petitioner's Exhibit No. MSH-3
Adjustment A08
Page 1 of 1

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Cost of Gas at Present Rates

Line No.	Category		
1	Adjustment to Revenue to Reflect Pro Forma Present Rate Revenue		$ (1,369,310)
2	Adjustment to Expenses to Reflect Pro Forma Cost of Gas		(780,450)
3	Pro Forma Margin Adjustments Attributable to:		
4	Increase in Unaccounted for Gas Costs	(576,734)	
5	Decrease in IURT on Cost of Gas	(12,126)	
6	Pro Forma Margin Adjustment to Reflect Pro Forma Cost of Gas		$ (588,860)

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Labor Costs for Existing Headcount

Line No.	Category		
1	Pro Forma Labor Costs	$	6,812,507
2	Less: Test Year Labor Costs		6,668,752
3	Pro Forma Increase in Labor Costs for Existing Headcount	$	143,755

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Labor Costs Pro Forma Adjustment

Line No.	As Allocated (during test year):	Direct Labor	Fringe Load 4/	Payroll Taxes 5/	Total
1	VVC allocated to Vectren South - Gas 1/	$ 1,184,376	$ 395,954	$ 90,385	$ 1,670,715
2	VUHI allocated to Vectren South - Gas 2/	1,487,951	497,492	113,600	2,099,043
3	Vectren South - Gas 3/	2,055,130	687,044	156,820	2,898,994
4		4,727,457	1,580,490	360,806	$ 6,668,752
	Current Level Annualized:	Direct Labor	Fringe Load	Payroll Taxes	Total
5	VVC allocated to Vectren South - Gas	$ 1,251,213	$ 422,910	$ 100,097	$ 1,774,220
6	VUHI allocated to Vectren South - Gas	1,649,181	557,423	131,934	2,338,539
7	Vectren South - Gas	1,903,913	643,523	152,313	2,699,749
8		4,804,307	1,623,856	384,345	$ 6,812,507
	Proforma Adjustment:	Direct Labor	Fringe Load	Payroll Taxes	Total
9	VVC allocated to Vectren South - Gas	$ 66,837	$ 26,956	$ 9,712	$ 103,505
10	VUHI allocated to Vectren South - Gas	161,230	59,931	18,334	239,495
11	Vectren South - Gas	(151,217)	(43,521)	(4,507)	(199,245)
12		76,850	43,366	23,539	$ 143,755

1/ VVC allocated to Gas is representative of shared services such as Accounting, IT, Legal, HR, etc.
2/ VUHI allocated to Gas is representative of utility shared services such as engineering, customer services
3/ Certain cost centers costs are allocated to gas such as fleet garage, and operations offices.
4/ The Fringe Load numbers include the costs of medical plans, dental plans, non-productive labor and misc health plans at rate of 33.3% and 33.8% for the years 2005 and 2006, respectively and 33.8% for the current level.
5/ Payroll Tax loading rate associated with the Vectren South - Gas labor dollars allocated was 7.5% and 8.0% for the test years 2005 and 2006, respectively, and 8.0% for the current level.

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Restricted Stock and Stock Option Expense
(Labor-Related Costs)

Line No.	Category		
1	Pro Forma Restricted Stock and Stock Option Expense	$	419,919
2	Less: Test Year Restricted Stock and Stock Option Expense		232,874
3	Pro Forma Increase in Restricted Stock and Stock Option Expense	$	187,046

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Restricted Stock and Stock Option Expense Pro Forma Adjustment

Line No.		Total	Restricted Stock	Restricted Stock Dividends	Stock Options
1	**Actual Expense for Test Year**				
2	Total Test Year Vectren Expense	$ 2,148,535	$ 1,896,602	$ 164,063	$ 87,871
3	Percent of Total Expense Allocated to Vectren South	44%			
4	**Total Vectren South Test Year Expense**	**$ 945,329**			
5	Percent Allocated to Vectren South - Gas	24.63%			
6	**Test Year Expense Allocated to Vectren South - Gas**	**232,874**			
7	**Calculation of Pro Forma Expense**				
8	Pro Forma Expense	$ 3,976,510	$ 3,492,885	$ 483,625	$ -
9	Percent of Total Pro Forma Expense Allocated to Vectren South	44%			
10	Pro Forma Expense Allocated to Vectren South	**$ 1,749,664**			
11	Percent Allocated to Vectren South - Gas	24.00%			
12	**Pro Forma Expense Allocated to Vectren South - Gas**	**$ 419,919**			

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Annual Incentive Compensation Expense
(Other Compensation)

Line No.	Category		
1	Pro Forma Annual Incentive Compensation Expense	$	443,936
2	Less: Test Year Annual Incentive Compensation Expense		426,418
3	Pro Forma Increase in Annual Incentive Compensation Expense	$	17,518

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Pension Expenses

Line No.	Category		
1	Pro Forma Pension Expenses	$	564,804
2	Less: Test Year Pension Expenses		517,653
3	Pro Forma Increase in Pension Expenses	$	47,152

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Pension Expense Pro Forma Adjustment

Line No.			
1	**Actual Expense for Test Year**		
2	Total Test Year Vectren Pension Cost	$	9,861,994
3	Percent of Total Cost Allocated to Expense		68.08%
4	Percent of Total Expense Allocated to Vectren South		43.96%
5	**Total Vectren South Test Year Expense**	**$**	**2,951,494**
6	Percent Allocated to Vectren South - Gas		17.54%
7	**Test Year Expense Allocated to Vectren South - Gas (Line 5 x Line 6)**	**$**	**517,653**
8	**Calculation of Pro Forma Expense**		
9	Total 2006 Budget for Vectren Pension Cost	$	10,745,745
10	Percent of Total Pro Forma Cost Allocated to Expense		69.25%
11	Percent of Total Pro Forma Expense Allocated to Vectren South		44.88%
12	Pro Forma Expense Allocated to Vectren South	**$**	**3,339,713**
13	Percent Allocated to Vectren South - Gas		16.91%
14	**Test Year Expense Allocated to Vectren South - Gas (Line 12 x Line 13)**	**$**	**564,804**

Petitioner's Exhibit No. MSH-3
Adjustment A13

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Postretirement Medical Expenses

Line No.	Category		
1	Pro Forma Postretirement Medical Expenses	$	154,608
2	Less: Test Year Postretirement Medical Expenses		224,261
3	Pro Forma Decrease in Postretirement Medical Expenses	$	(69,653)

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Postretirement Medical Expenses Pro Forma Adjustment

Line No.			
1	**Actual Expense for Test Year**		
2	Total Test Year Vectren Cost	$	4,272,473
3	Percent of Total Cost Allocated to Expense		68.08%
4	Percent of Total Expense Allocated to Vectren South		43.96%
5	**Total Vectren South Expense for Test Year**	**$**	**1,278,664**
6	Percent Allocated to Vectren South - Gas		**17.54%**
7	**Test Year Expense Allocated to Vectren South - Gas (Line 5 x Line 6)**	**$**	**224,261**
8	**Calculation of Pro Forma Expense**		
9	Total Vectren Expense Net of Asset Return per 2006 Budget	$	4,173,341
10	Asset Return Specific to Vectren South		555,487
11	Gross Pro Forma Vectren Cost		4,728,828
12	Percent of Total Pro Forma Cost Allocated to Expense		69.25%
13	Percent of Total Pro Forma Expense Allocated to Vectren South		44.88%
14	Gross Pro Forma Expense Allocated to Vectren South		1,469,691
15	Total Asset Return to Vectren South		(555,487)
16	**Pro Forma Expense to Vectren South**	**$**	**914,204**
17	Percent Allocated to Vectren South - Gas		**16.91%**
18	**Test Year Expense Allocated to Vectren South - Gas (Line 16 x Line 17)**	**$**	**154,608**

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Distribution Operations Training Expenses

Line No.	Category	
1	Pro Forma Increase in Distribution Operations Training Expenses	$ 37,088

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Incremental Headcount Expenses
(Additional Employees)

Line No.	Category	
1	Pro Forma Increase in Labor and Labor Related Costs for Increased Headcount	$ 213,932

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Pro Forma Miscellaneous Headcount Expenses

Line No.	Incremental Positions	Labor	Labor Related Costs	Total
1	Human Resources Accounting Clerk - Benefits invoice processing	$ 39,800	$ 23,482	$ 63,282
2	Contract Administration Manager and Clerk (2 FTE's) - requirement for legal, regulatory and SOX compliance	118,750	71,250	190,000
3	Internal Auditor - staff auditor	48,500	28,615	77,115
4	Productivity Analyst - continued development of continuous improvement program	65,000	39,000	104,000
5	Forecasting Manager - evaluation of financial transactions	100,000	59,000	159,000
6	Financial Analysts (2 FTE's) - financial transaction accuracy	85,500	50,445	135,945
7	Economic Development Representative - (1 FTE) - timely reponse to customer feedback	47,112	27,796	74,908
8	Marketing Director, Manager - (2 FTE's) - timely reponse to customer feedback	211,723	124,916	336,639
9	Training Specialist (1 FTE's) - safety/industrial hygiene to ensure proper training, safe work environment	94,340	55,660	150,000
10	Miscellaneous Billing Supervisor and Specialists (12 FTE's) - requirement for bill processing	496,928	293,187	790,115
11	Headcount Adjustment - Total Cost	$ 1,307,652	$ 773,352	$ 2,081,004
	Incremental Positions Allocated to Vectren South Gas			
12	Human Resources Accounting Clerk - Benefits invoice processing	$ 4,203	$ 2,480	$ 6,683
13	Contract Administration Manager and Clerk (2 FTE's) - requirement for legal, regulatory and SOX compliance	13,680	8,208	21,888
14	Internal Auditor - staff auditor	5,587	3,296	8,884
15	Productivity Analyst - continued development of continuous improvement program	6,552	3,931	10,483
16	Forecasting Manager - evaluation of financial transactions	10,080	5,947	16,027
17	Financial Analysts (2 FTE's) - financial transaction accuracy	8,456	4,989	13,445
18	Economic Development Representative - (1 FTE) - timely reponse to customer feedback	4,659	2,749	7,408
19	Marketing Director, Manager - (2 FTE's) - timely reponse to customer feedback	20,939	12,354	33,294
20	Training Specialist (1 FTE's) - safety/industrial hygiene to ensure proper training, safe work environment	9,330	5,505	14,835
21	Miscellaneous Billing Supervisor and Specialists (3 FTE's) - requirement for bill processing	50,934	30,051	80,985
22	Pro Forma Increase for Incremental Headcount Allocated to Vectren South - Gas	$ 134,421	$ 79,511	$ 213,932

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Workforce Aging Costs

Line No.	Category	
1	Pro Forma Increase to Reflect Workforce Aging Costs	$ 430,411

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma for Manufactured Gas Plant Expense

Line No.	Category	
1	Pro Forma Manufactured Gas Plant Expense	$ -
2	Less: Test Year Manufactured Gas Plant Expense	316,500
3	Pro Forma Decrease in Manufactured Gas Plant Expense	$ (316,500)

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pipeline Safety Act Costs

Line No.	Category		
1	Pro Forma Pipeline Safety Act Costs	$	500,000
2	Less: Test Year Pipeline Safety Act Costs		390,665
3	Pro Forma Increase in Pipeline Safety Act Costs	$	109,335

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Distribution Maintenance

Line No.	Category	
1	Pro Forma Increase in Distribution Maintenance	$ 636,600

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Uncollectible Accounts

Line No.	Category	
1	Going Level Present Rate Revenue	$ 155,034,212
2	Five Year Average of Actual Write-Offs	0.74%
3	Pro Forma Uncollectible Accounts Expense	1,147,253
4	Less: Test Year Uncollectible AccountsExpense	342,271
5	Pro Forma Increase in Uncollectible AccountsExpense	$ 804,982

Petitioner's Exhibit No. MSH-3
Adjustment A21

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Meter Reading Expenses

Line No.	Catergory	
1	Pro Forma Increase in Meter Reading Expenses	$ 26,001

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Increase in Customer Contact Center Expenses

Line No.	Category	
1	Pro Forma Increase in Customer Contact Center Expenses	$ 118,466

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Increase in Economic Development Sales and Marketing Expenses

Line No.	Category	
1	Pro Forma Increase in Economic Development Sales and Marketing Expenses	$ 71,735

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Increase in Postage and Miscellaneous Billing Expenses

Line No.	Category	
1	Pro Forma Increase in Postage and Miscellaneous Billing Expenses	$ 15,627

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Calculation of Increase in Postage and Miscellaneous Billing Expenses

Line No.			
1	Vectren Postage Expense Under $0.37 Postage Rate (April 2005 - December 2005)	$	2,748,327
2	Percent Increase in Postage Rate, Effective January 1, 2006		5.4%
3	Pro Forma Increase in Postage Expense for Vectren (Line 1 x Line 2)	$	148,410
4	Pro Forma Increase in Miscellaneous Billing Costs	$	9,600
5	Total Vectren Pro Forma Increase in Customer Records and Collection Expense (Line 3 + Line 4)	$	158,010
6	Percent Allocated to Vectren South		23%
7	Vectren South Pro Forma Increase in Customer Records and Collection Expense (Line 5 x Line 6)	$	36,342
8	Percent Allocated to Vectren South-Gas		43%
9	Pro Forma Increase in Customer Records and Collection Expense Allocated to Vectren South-Gas (Line 7 x Line 8)	$	15,627

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Increase in Information Technology Expenses

Line No.	Category	
1	Pro Forma Increase in Information Technology Maintenance and Other Costs	$ 76,141

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Information Technology Pro Forma Adjustment

Line No.	Category		
1	Reduced External Contractor Expense for Information Technology Help Desk	$	(120,049)
2	Increase in Maintenance, Hardware and Communication Expenses		885,545
3	Total Adjustment for Information Technology Maintenance and Other Costs - Vectren	$	765,496
4	Pro Forma Increase in Information Technology Maintenance and Other Costs Allocated to Vectren South - Gas	$	76,141

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Amortization of Rate Case Expenses

Line No.	Category		
1	Pro Forma Rate Case Amortization Expense	$	245,418
2	Less: Test Year Rate Case Amortization Expense		201,803
3	Pro Forma Increase in Rate Case Amortization Expense	$	43,615

VECTREN SOUTH
GAS TARIFF
PROFORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Amortization of Rate Case Expenses

Line No.			
1	Expected Rate Case Expenses	$	484,000
2	Estimated Unamortized Rate Case Expense from Cause No. 42596 as of March 31, 2007		252,253
3	Total Rate Case Expenses to be Amortized (Sum of Line 1 and Line 2)		736,253
4	Amortization Period (Years)		3
5	Pro Forma Rate Case Amortization Expense (Line 3 divided by Line 4)	$	245,418

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Amortization of the Pipeline Safety Act Cost Deferral

Line No.	Category		
1	Estimated Expense Balance in Accordance with Cause No. 42596	$	1,595,657
2	Amortization Period (Years)		3
3	Annual Amortization of Deferred Pipeline Safety Act Costs	$	531,886

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTHS ENDING MARCH 31, 2006

Supporting Schedule for Amortization of the Pipeline Safety Act Cost Deferral

Line No.			
1	Total Incremental Expense Deferred through 3-31-06	$ 1,821,020	
2	Less: Recoveries through 3-31-06	(390,665)	
3	Deferral per Books at 3-31-06	1,430,355	
4	Less: 2006 PSA Tracker Filing- Cause No. 42596	(604,849)	
5	Deferrals to be Recovered	825,506	
6	Less: Remaining Estimated Recoveries from Year One Filing	(129,741)	a)
7	Expected Deferred Balance after 2006 Filing	695,765	
8	Plus: Estimated Costs 4-1-06 through 3-31-07	1,399,892	b)
9	Less: 2007 PSA Filing	(500,000)	c)
10	Estimated Expense Balance in Accordance with Cause No. 42596	$ 1,595,657	

a) $625,255 filed in Cause No. 42596 less $495,514 approved recovery through 3-31-06
b) Estimated costs based on High Consequence Area Mileage
c) Reflects annual cap amount

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Property and Risk Insurance Expense

Line No.	Category		
1	Pro Forma Property and Risk Insurance Expense	$	535,520
2	Less: Test Year Property and Risk Insurance Expense		647,625
3	Pro Forma Decrease in Property and Risk Insurance Expense	$	(112,105)

VECTREN SOUTH
GAS TARIFF
PROFORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Property and Risk Insurance Pro Forma Adjustment

Line No.	Risk Insurance Based on Proposed 2006-2007 Premiums		
	Common Risk Insurance Premiums:		
1	Workers Compensation	$ 285,926	
2	Automobile Liability	224,984	
3	Excess Liability	2,204,891	
4	Directors & Officers Liability	1,193,186	
5	Blanket Crime	19,898	
6	Fiduciary Liability	161,825	
7	Miscellaneous Liability	1,915	
8	Total Pro-Forma Risk Insurance Expense	$ 4,092,625	
9	Allocation Factor to Vectren South	44%	
10	Total Vectren South Pro Forma Risk Insurance Expense	$ 1,800,755	
11	Allocation Factor to Vectren South - Gas	24%	
12	Pro Forma Vectren South - Gas Common Risk Insurance	$ 432,181	$ 432,181
	Vectren South Risk Insurance Premiums:		
13	Garagekeepers Liability	$ 1,932	
14	Allocation Factor to Vectren South - Gas	24%	
15	Pro Forma Vectren South - Gas Common Risk Insurance	$ 464	$ 464
	Vectren South Gas Risk Insurance Premiums:		
16	Hoosier Division Risk Insurance	$ 13,956	$ 13,956
17	Total Vectren South-Gas Pro-Forma Risk Insurance Expense (Sum of Lines 12, 15 and 16)		$ 446,601
	Property Insurance Based on Proposed 2006-2007 Premiums		
	Above Ground Property Insurance Premiums:		
18	Property Insurance -- Above Ground Property	$ 1,814,000	
19	Allocation Factor to Vectren South - Gas	1.2%	
20	Total Pro Forma Vectren South - Gas Property Insurance	$ 21,768	$ 21,768
	Below Ground Property Insurance Premiums:		
21	Property Insurance -- Below Ground Property	$ 610,465	
22	Allocation Factor to Vectren South - Gas	11%	
23	Total Vectren South-Gas Pro Forma Property Insurance Expense	$ 67,151	$ 67,151
24	Total Vectren South- Gas Pro-Forma Property Insurance Expense (Sum of Lines 20 and 23)		$ 88,919
25	Total Pro Forma Property and Risk Insurance Expense Allocated to Vectren South - Gas (Lines 17 and 24)		$ 535,520

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Claims Expense

Line No.	Category		
1	Pro Forma Claims Expense	$	582,181
2	Less: Test Year Claims Expense		556,793
3	Pro Forma Increase in Claims Expense	$	25,388

VECTREN SOUTH
GAS TARIFF
PROFORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Claims Expense Pro Forma Adjustment

Line No.	Claims Paid		
1	12 months ended March 31, 2006	$ 1,111,199	
2	12 months ended March 31, 2005	91,038	
3	12 months ended March 31, 2004	44,307	
4	Total Claims Paid During Last Three Years	1,246,544	
5	Three Year Average of Claims Paid (Line 4 divided by 3)		415,514
	Major Claims Expensed in Test Year		
6	Single Claim Expensed in Test Year	$ 500,000	
7	Three Year Amortization of Major Claims Expense (Line 6 divided by 3)		166,667
8	Total Claims Expense (Line 5 + Line 7)		$ 582,181

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Rent Expense
(Other Cost Reductions)

Line No.	Category	
1	Pro Forma Decrease in Rent Expense from Former Corporate Headquarters	$ (33,227)

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Cost Allocations

Line No.	Category	
1	Pro Forma Change in Cost Allocations	$ 28,011

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Cost Allocations Pro Forma Adjustment

Line No.			
	Test Year		
1	A&G Credit	$	(445,000)
2	Change in Allocation Drivers		448,103
3	Adjustment to Charges in Cost Centers		207,188
4	AGA Dues Paid in Advance		26,242
5	Test Year Impacts	$	236,533
	Pro Forma		
6	A&G Credit	$	(450,849)
7	Change in Allocation Drivers		299,969
8	Adjustment to Charges in Cost Centers		415,424
9	Removal of Dues Paid in Advance		-
10	Pro Forma Impacts	$	264,544
11	Pro Forma Change in Cost Allocations (Line 10 - Line 5)	$	28,011

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Asset Management Program Costs

Line No.	Category	
1	Pro Forma Increase in Asset Management Program Costs Allocated to Vectren South - Gas	$ 78,131

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Pro Forma Asset Management Program Savings

Line No.	Category	
1	Pro Forma Increase in Asset Management Program Savings Allocated to Vectren South - Gas	$ (18,599)

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment for Indiana Utility Regulatory Commission (IURC) Fee

Line No.	Category		
1	Pro Forma Revenue	$	155,034,212
2	IURC Rate		0.11%
3	Pro Forma IURC Fees		170,538
4	Less: Test Year IURC Fees		69,606
5	Pro Forma Increase in IURC Fees	$	100,932

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment to Reflect Asset Charge

Line No.		
1	Utility Holdings Gross Plant Balance at March 31, 2006	$ 235,090,990
2	Accumulated Reserve for Depreciation	(94,214,554)
3	Utility Holdings Net Plant Balance at March 31, 2006	140,876,436
4	Pro Forma Weighted Average Cost of Capital Grossed Up for Income Taxes	11.73%
5	Asset Cost-Return and Income Taxes (Line 3 x Line 4)	16,524,806
6	Total Depreciation Expense	21,148,656
7	Total Property Taxes	1,069,000
8	Total Charges	38,742,462
9	Blended Allocation Factor to Vectren South - Gas	8.97%
10	Total Pro Forma Asset Charge (Line 8 x Line 9)	3,475,132
11	Less Test Year Asset Charge	3,306,657
12	Pro Forma Increase in Asset Charge	$ 168,475

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Calculation of Weighted Average Cost of Capital

Line No.	WACC	%	Gross-up for taxes	Pre-tax WACC
1	Equity	5.53%	59.475%	9.30%
2	LTD	2.33%		2.33%
3	Other (Equity, Customer Deposits)	0.10%		0.10%
4	Weighted Average Cost of Capital	7.96%		11.73%
5	One	100.00%		
6	State Income Tax Rate	8.50%		
7	One Minus State Income Tax Rate		91.50%	
8	One	100.00%		
9	Federal Income Tax Rate	35.00%		
10	One Minus Federal Income Tax Rate		65.00%	
11	Gross-up Factor			59.475%

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Pro Forma Adjustment to Depreciation Expense

Line No.	Category	
1	Pro Forma Depreciation Expense	$ 5,544,105
2	Less: Test Year Depreciation Expense	5,351,597
3	Pro Forma Increase in Depreciation Expense	$ 192,508

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Depreciation Pro Forma Adjustment

DEPRECIABLE BALANCE
As of 3/31/06

Line No.		Plant in Service Balance	CCNC Balance	Annual Deprec. Rate	Annual Depreciation
1	301 Organization	$ 10,054	$ -	$ -	$ -
2	302 Franchise and Consents	454	-	0.00	-
3	330 Prod Gas Wells - Const	29,161	-	0.00	-
4	331 Prod Gas Wells - Equipment	15,141	-	0.00	-
5	332 Field Lines	9,942	-	0.00	-
6	350.1 Land	6,971,745	-	0.00	-
7	351 Compressor Station Strct	107,134	-	1.66	1,778
8	351 Meas & Reg Station Strct	87,586	-	1.95	1,708
9	351 Other Structures	125,458	-	1.52	1,907
10	352 Wells	1,575,250	-	2.13	33,553
11	352.1 Storage Leaseholds & Rt	1,087,081	-	1.90	20,654
12	352.3 Non-Recoverable Nat Gas	483,848	-	1.89	9,145
13	353 Lines	807,716	4,530	2.16	17,544
14	354 Compressor Station Equip	338,846	-	1.73	5,862
15	355 Measuring & Regulating Eq	592,823	54,262	3.02	19,542
16	356 Purification Equipment	293,374	-	3.35	9,828
17	365.1 Land and Land Rights	316,494	139,155	0.00	-
18	365.2 Rights-of-Way	935,391	118,476	2.18	22,974
19	366 Meas & Reg Station Strct	209,233	14,465	2.35	5,257
20	367 Mains	22,034,392	1,670,032	2.77	656,612
21	368 Compressor Station Equip	27,708	-	3.51	972
22	369 Meas & Reg Station Equip	3,487,641	521,848	4.97	199,272
23	371 Other Equipment	4,511	1,915	4.02	258
24	374 Land Rights	71,015	48,145	0.00	-
25	375 Structures & Improvements	122,914	(7,317)	2.11	2,439
26	376 Mains	62,726,646	9,146,595	2.71	1,947,765
27	378 Meas & Reg Station Eq-Gen	1,852,009	753,557	3.02	78,688
28	380 Services	49,070,271	103,546	3.49	1,716,166
29	381 Meters	12,261,676	48,528	3.85	473,943
30	382 Meter Installations	448,989	315	3.38	15,186
31	383 House Regulators	416,792	-	3.04	12,670
32	384 House Regulator Install	121,259	-	2.86	3,468
33	385 Indus Meas & Reg St Equip	1,982	13,004	3.51	526
34	387 Other Equipment	11,433	18,852	4.21	1,275
35	389 Land and Land Rights	-	-	0.00	-
36	390 Structures & Improvements	30,885	-	2.60	803
37	391 Electronic Equipment	364,906	-	2.48	9,050
38	391 Furniture & Fixture	39,238	-	3.96	1,554
39	392 Automobiles	123,137	183,605	11.21	34,386
40	392 Light Trucks	1,048,055	523,320	8.95	140,638
41	392 Trailers	110,364	3,734	3.17	3,617
42	392 Heavy Trucks	1,558,320	245,317	6.71	121,024
43	393 Stores Equipment	3,679	-	0.00	-
44	394 Tools, Shop & Garage Equip	840,245	26,439	3.87	33,541
45	395 Laboratory Equipment	344,980	-	4.85	16,732
46	396 Power Operated Equipment	1,555,149	63,476	2.26	36,581
47	397 Communication Equipment	140,098	-	4.03	5,646
48	398 Miscellaneous Equipment	137,183	-	3.97	5,446
49	303 Miscellaneous Int Plant	6,176	-	10.00	618
50	389 Land	286,439	-	0.00	-
51	390 Structures and Improvement	3,030,458	81,080	2.84	88,368
52	391 Electronic Equipment	376,280	533	17.30	65,189
53	391 Furniture & Fixtures	133,838	7,726	4.29	6,073
54	392 Automobiles	28,591	1,918	5.27	1,608
55	392 Light Trucks	43,407	2,380	13.57	6,213
56	392 Trailers	669	-	3.86	26
57	392 Heavy Trucks	-	14,814	5.21	772
58	392 Light Trucks - Non-Depr	227	-	0.00	-
59	393 Stores Equipment	53,426	493	3.79	2,044
60	394 Tools, Shop & Garage Equip	39,097	285	0.65	256
61	396 Power Operated Equipment	5,959	-	2.86	170
62	397 Communication Equipment	339,833	721	3.63	12,362
63	398 Miscellaneous Equipment	27,972	205	2.41	679
64		$ 177,324,574	$ 13,805,955		$ 5,852,388
65	Less:				
66	392 Transportation Equipment (FERC 184)	2,912,770	975,088		308,284
67	Depreciation Expense				$ 5,544,105

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment of State Income Tax at Current Rates

Line No.	Catergory			
1	Pro Forma Gross Margin		$	36,040,653
2	Operation and Maintenance Expenses			(19,971,906)
3	Asset Charge			(3,475,132)
4	Depreciation			(5,544,105)
5	Property Taxes			(902,729)
6	Income Before IURT and Income Taxes			6,146,781
7	Less: Interest Synchronization			(2,855,378)
8	Add: Permanent Differences			
9	Book Depreciation on Non-Deferred Basis	289,445		
10	Medicare Act Subsidy	(20,223)		
11	Other Non Deductible Expenses	4,393		
12	Permanent Differences			273,615
13	Income Before State Taxes			3,565,018
14	State Income Tax Rate			8.5%
15	Pro Forma Provision for State Income Taxes (Line 13 x Line 14)			303,027
16	Less: Test Year Provision for State Income Taxes			1,055,982
17	Pro Forma Decrease in State Income Taxes at Current Rates		$	(752,955)

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment of Federal Income Tax at Current Rates

Line No.	Category		
1	Income Before IURT and Income Taxes		$ 6,146,781
2	Less: Interest Synchronization		(2,855,378)
3	Add: Permanent Differences		
4	Book Depreciation on Non-Deferred Basis	289,445	
5	Medicare Act Subsidy	(20,223)	
6	Other Non Deductible Expenses	4,393	
7	Permanent Differences		273,615
8	IURT		(2,154,403)
9	Pro Forma State Income Taxes		(303,027)
10	Federal Taxable Income		1,107,588
11	Federal Income Tax Rate		35%
12	Federal Income Taxes (Line 10 x Line 11)		387,656
13	Less: Amortization of Investment Tax Credit		(70,072)
14	Pro Forma Provision for Federal Income Taxes		317,584
15	Less: Test Year Provision for Federal Income Taxes		1,361,999
16	Pro Forma Decrease in Federal Income Taxes at Current Rates		$ (1,044,415)

Petitioner's Exhibit No. MSH-3
Adjustment A39
Page 1 of 1

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment for Indiana Utility Receipts Tax

Line No.	Category	
1	Going Level Present Rate Revenue	$ 155,034,212
2	Less: Uncollectible Accounts Expense	(1,147,253)
3	Statutory Exemption	(1,000)
4	Pro Forma Margins Subject to Indiana Utility Receipts Tax	153,885,959
5	IURT tax rate	1.40%
6	Pro Forma Utility Receipts Tax	2,154,403
7	Less: Test Year Indiana Utility Receipts Tax	2,028,367
8	Pro Forma Increase in Indiana Utility Receipts Tax	$ 126,036

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment for Property Tax Expense

Line No.	Category	
1	Pro Forma Property Tax Expense	$ 902,729
2	Less: Test Year Property Tax Expense	1,015,616
3	Pro Forma Decrease in Property Tax Expense	$ (112,887)

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Supporting Schedule for Property Tax Pro Forma Adjustment

Line No.			
1	2006 Property Tax Payments - Vectren South	$	8,372,026
2	Three Year Compound Annual Growth in Rate and Assessed Value		8.42%
3	Pro Forma Property Tax Expense - Vectren South	$	9,076,850
4	Property Tax Expense Allocated to Vectren South - Gas	$	902,729

VECTREN SOUTH
GAS TARIFF
Calculation of Proposed Revenue Increase
Based on Pro Forma Operating Results
Original Cost Rate Base Estimated at March 31 , 2006

Revenue Increase Based on Net Original Cost Rate Base

Line No.		
1	Net Original Cost Rate Base	$ 118,480,432
2	Rate of Return	7.96%
3	Required Net Operating Income (Line 1 x Line 2)	9,431,041
4	Pro Forma Net Operating Income	3,371,759
5	Increase in Net Operating Income	6,059,283
6	Effective Incremental Revenue/NOI Conversion Factor	58.1%
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5/Line 6)	$ 10,436,340

8	One		1.000000			
9	Less: IURC Fee		0.001100			
10	Less: Indiana Utility Receipts Tax		0.014000			
11	Less: Bad Debt		0.007400			
12	One Less Bad Debt, IURC Fee and IURT			0.977500		
13	One	1.000000				
14	Less: IURC Fee	0.001100				
15	Less: Bad Debt	0.007400				
16	Taxable Adjusted Gross Income Tax		0.991500			
17	Adjusted Gross Income Tax Rate		0.085000			
18	Adjusted Gross Income Tax			0.084278		
19	Line 12 less line 18				0.893223	
20	One			1.000000		
21	Less: Federal Income Tax Rate			0.350000		
22	One Less Federal Income Tax Rate				0.650000	
23	Effective Incremental Revenue/NOI Conversion Factor (line 19 times line 22)					58.1%

VECTREN SOUTH
GAS TARIFF
Statement of Gas Property
Original Cost Ratebase at March 31, 2006

Line No.	Activity (FERC) No.	Description	Gas Plant Per Books at March 31, 2006	Eliminations	As Adjusted Rate Base at March 31, 2006
		Utility Plant			
1	101	In Service - Unitized	$ 176,967,759		$ 176,967,759
2	105	Property Held for Future Use			
3	106	Completed Const. Not Classified	14,162,771		14,162,771
4	107	Const. Work in Progress	3,721,150	(3,721,150)	0
5			194,851,680	(3,721,150)	191,130,530
		Accumulated Depreciation			
6	108	Utility Plant	(80,229,095)		(80,229,095)
7		Net Utility Plant	114,622,585	(3,721,150)	110,901,435
		Material & Supplies (13 Month Average)			
8	154	Utility Material & Supplies	605,003		605,003
9	163	Stores Expense	402,626		402,626
10	164	Gas in Underground Storage	6,571,368		6,571,368
11		Total Material & Supplies	7,578,997		7,578,997
12		TOTAL	$ 122,201,582	$ (3,721,150)	$ 118,480,432

VECTREN SOUTH
GAS TARIFF
Capital Structure and Cost of Capital
Twelve months ending March 31, 2006

Line No.	Type of Capital	Amount ($000's)	Percent	Cost	WCOC
1	**Long-Term Debt**				
2	Publicly Held	$ 228,165	19.54%		
3	Notes to VUHI	223,182	19.11%		
4	Total Long-Term Debt	$ 451,347	38.65%	6.04%	2.33%
5	**Common Equity**				
6	Common Stock	$ 273,263	23.40%		
7	Retained Earnings	274,999	23.55%		
8	Accumulated Comprehensive Income	1,246	0.11%		
9	Common Shareholder's Equity	$ 549,508	47.05%	11.75%	5.53%
10	**Investor Provided Capital**	1,000,855	85.70%		7.86%
11	**Customer Deposits**	5,601	0.48%	5.39%	0.03%
12	**Cost Free Capital:**				
13	Deferred Income Taxes	$ 138,730	11.88%		
14	Customer Advances for Construction	2,211	0.19%		
15	SFAS 106	11,536	0.99%		
16	Total Cost Free Capital	$ 152,477	13.06%	0.00%	0.00%
17	**Job Development Investment Tax Credit (Post-1971)**	$ 8,920	0.76%	9.18%	0.07%
18	**Total Capitalization**	$ 1,167,853	100.00%		
19	**Rate of Return**				7.96%

Investor Provided Capital

Line No.		Amount ($000's)	Percent	Cost	WCOC
20	Long-Term Debt	$ 451,347	45.10%	6.04%	2.72%
21	Common Equity	549,508	54.90%	11.75%	6.45%
22	Total Capitalization	$ 1,000,855	100.00%		9.17%

Interest Synchronization

Line No.		Percent	Cost	Weighted Cost
23	Long-term Debt	38.65%	6.04%	2.33%
24	Customer Deposits	0.48%	5.39%	0.03%
25	Interest Component of ITC	0.76%	6.04%	0.05%
26	Total			2.41%
27	Original Cost Rate Base			$ 118,480,432
28	Synchronized Interest Expense			$ 2,855,378

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment for Uncollectible Accounts on Revenue Increase

Line No.	Category	
1	Pro Forma Increase in Revenue Requirement	$ 10,436,340
2	Five Year Average of Actual Write-offs	0.74%
3	Pro Forma Increase in Uncollectible Accounts Expense	$ 77,229

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment for IURC Fees on Revenue Increase

Line No.	Category	
1	Pro Forma Increase in Revenue Requirement	$ 10,436,340
2	Indiana IURC Rate	0.11%
3	Pro Forma Increase in IURC Fees	$ 11,480

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment of State Income Tax at Proposed Rates

Line No.	Category		
1	Pro Forma Increase in Requirement Revenue	$	10,436,340
2	Less: Additional IURC Fee		(11,480)
3	Less: Additional Uncollectible Accounts Expense		(77,229)
4	Income Before IURT and Income Taxes		10,347,631
5	State Tax Rate		8.5%
6	Pro Forma Increase in State Income Tax at Proposed Rates	$	879,549

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment of Federal Income Tax at Proposed Rates

Line No.	Category		
1	Pro Forma Increase in Requirement Revenue	$	10,436,340
2	Less: Additional IURC Fee		(11,480)
3	Less: Additional IURT		(146,109)
4	Less: Additional State Income Taxes		(879,549)
5	Less: Additional Uncollectible Accounts Expense		(77,229)
6	Incremental Federal Taxable Income		9,321,973
7	Federal Tax Rate		35%
8	Pro Forma Increase in Federal Income Tax at Proposed Rates	$	3,262,691

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Adjustment for Indiana Utility Receipts Tax for Additional Revenue Requirement

Line No.	Category		
1	Pro Forma Increase in Revenue Requirement	$	10,436,340
2	Indiana Utility Receipts Tax Rate		1.40%
3	Pro Forma Increase in Indiana Utility Receipts Tax	$	146,109

VECTREN SOUTH
GAS TARIFF
PRO FORMA AT PRESENT RATES
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

	A	B		C = A + B
	Test Year 12 Mos Ended 3/31/06	**Pro Forma Adjustment**	**Pro Forma Adjustment Ref**	**Test Year Pro Forma at Present Rates**
Manufactured Gas Production Operation				
710 Operation Supervision & Engineering	$ -	$ -		$ -
712 Other Power Expenses	$ -	$ -		$ -
717 Liquified Petroleum Gas Expenses	$ -	$ -		$ -
728 Liquified Petroleum Gas	$ -	$ -		$ -
735 Misc Production Expenses	$ -	$ -		$ -
736 Rents	$ -	$ -		$ -
Total Manufactured Gas Production Operation	$ -	$ -		$ -
Manufactured Gas Production Maintenance				
740 Maintenance Supervision & Engineering	$ -	$ -		$ -
741 Maintenance of Structures & Improvements	$ 316,500	$ (316,500)	A17	$ -
742 Maintenance of Production Equipment	$ -	$ -		$ -
Total Manufactured Gas Production Maintenance	$ 316,500	$ (316,500)		$ -
Production Operation				
750 Operation Supervision & Engineering	$ -	$ -		$ -
752 Gas Wells Expenses	$ -	$ -		$ -
753 Field Lines Expenses	$ -	$ -		$ -
Total Production Operation	$ -	$ -		$ -
Production Maintenance				
761 Maintenance Supervision & Engineering	$ -	$ -		$ -
763 Maintenance of Producing Gas Wells	$ -	$ -		$ -
764 Maintenance of Field Wells	$ -	$ -		$ -
Total Production Maintenance	$ -	$ -		$ -
Stored Gas Operations				
814 Operation Supervision and Engineering	$ 81,664	$ 58	A09	$ 81,722
815 Maps and Records	$ -	$ -		$ -
816 Wells Expenses	$ 64,810	$ -		$ 64,810
817 Lines Expense	$ 61,268	$ 26	A09	$ 61,294
818 Compressor Station Expense	$ 109,170	$ -		$ 109,170
819 Compressor Station Fuel & Power	$ -	$ -		$ -
820 Measuring and Regulating Station	$ -	$ -		$ -
821 Purification Expenses	$ 91,831	$ -		$ 91,831
822 Exploration and Development	$ -	$ -		$ -
824 Other Expenses	$ -	$ -		$ -
825 Storage Well Royalties	$ -	$ -		$ -
826 Rents	$ 1,837	$ -		$ 1,837
Total Stored Gas Operatons	$ 410,580	$ 84		$ 410,664
Stored Gas Maintenance				
830 Maintenance Supervision & Engineering	$ -	$ -		$ -
831 Maintenance of Structures and Improvements	$ 43,845	$ -		$ 43,845
832 Maintenance of Reservoirs and Wells	$ 27,925	$ -		$ 27,925
833 Maintenance of Lines	$ 62,363	$ 2	A09	$ 62,365
834 Maintenance of Compression Station Equipment	$ 100,966	$ -		$ 100,966
835 Maintenance of Meas. & Reg. Station Equipment	$ 1,482	$ 25	A09	$ 1,507
836 Maintenance of Purification Equipment	$ 13,322	$ -		$ 13,322
837 Maintenance of Other Equipment	$ -	$ -		$ -
Total Stored Gas Maintenance	$ 249,903	$ 27		$ 249,930
Transmission Operation				
850 Operation Supervision and Engineering	$ 58,365	$ 18,756	A16	$ 77,121
851 System Control and Load Dispatching	$ (4,879)	$ -		$ (4,879)
856 Mains Expenses	$ 444,704	$ 659,684	A09, A16, A18, A27	$ 1,104,388
857 Measuring and Regulating Station Expenses	$ 125,332	$ 1,171	A09	$ 126,503
859 Other Expenses	$ -	$ -		$ -
860 Rents	$ 845	$ -		$ 845
Total Transmission Operation	$ 624,368	$ 679,611		$ 1,303,979
Transmission Maintenance				
861 Maintenance Supervision and Engineering	$ -	$ -		$ -
862 Maintenance of Structures and Improvements	$ 14,903	$ 218,256	A09, A19	$ 233,159
863 Maintenance of Mains	$ 213,134	$ 242,993	A09, A16, A19, A32	$ 456,127
865 Maintenance of Measuring and Reg Station Equipment	$ 8,792	$ 312	A09	$ 9,104
866 Maintenance of Communication Equipment	$ -	$ -		$ -
867 Maintenance of Other Equipment	$ 3,944	$ 49	A09	$ 3,993
Total Transmission Maintenance	$ 240,774	$ 461,610		$ 702,384
Distribution Operations				
870 Operation Supervision and Engineering	$ 379,309	$ 24,798	A09, A16	$ 404,107
871 Distribution Load Dispatching	$ -	$ -		$ -
872 Compressor Station Labor & Expenses	$ -	$ -		$ -
873 Compressor Station Fuel & Power	$ -	$ -		$ -
874 Mains and Services Expenses	$ 508,959	$ 58,271	A09, A16	$ 567,230
875 Measuring and Regulating Stations Expenses-General	$ 131,567	$ 1,370	A09	$ 132,937
876 Measuring and Regulating Stations Expenses-Industrial	$ -	$ -		$ -
877 Measuring and Regulating Stations Expenses-City Gate Check Stations	$ -	$ -		$ -
878 Meter and House Regulator Expenses	$ 162,499	$ 2,573	A09	$ 165,072
879 Customer Installation Expenses	$ 615,522	$ (8,258)	A09, A33	$ 607,264
880 Other Expenses	$ 491,165	$ 93,343	A09, A14, A15, A16	$ 584,508
881 Rents	$ 105	$ -		$ 105
Total Distribution Operations	$ 2,289,126	$ 172,097		$ 2,461,223

VECTREN SOUTH
GAS TARIFF
PRO FORMA AT PRESENT RATES
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

	A	B		C = A + B
	Test Year 12 Mos Ended 3/31/06	**Pro Forma Adjustment**	**Pro Forma Adjustment Ref**	**Test Year Pro Forma at Present Rates**
Distribution Maintenance				
885 Maintenance Supervision and Engineering	$ 305,787	$ 18,096	A09, A32	$ 323,883
886 Maintenance of Structures and Improvements	$ 5,491	$ 218,283	A09, A19	$ 223,774
887 Maintenance of Mains	$ 1,131,354	$ 101,174	A09, A16, A19	$ 1,232,528
888 Maintenance of Compressor Station Equipment	$ -	$ -		$ -
889 Maintenance of Measuring and Regulating Station Equipment-General	$ 40,736	$ 599	A09	$ 41,335
890 Maintenance of Meas. & Reg. Station Equipment-Industrial	$ -	$ -		$ -
891 Maintenance of Meas. & Reg. Station Equipment-City Gate Check Stations	$ -	$ -		$ -
892 Maintenance of Services	$ 582,495	$ 9,080	A09	$ 591,575
893 Maintenance of Meters and House Regulators	$ 129,435	$ 1,794	A09	$ 131,229
894 Maintenance of Other Equipment	$ 45,383	$ 351	A09	$ 45,734
Total Distribution Maintenance	$ 2,240,681	$ 349,377		$ 2,590,058
Customer Accounts				
901 Supervision (Customer Accounts)	$ 183,784	$ 14,266	A09, A15	$ 198,050
902 Meter Reading Expenses	$ 857,648	$ 32,759	A09, A21	$ 890,407
903 Customer Records and Collection	$ 1,927,691	$ 220,954	A09, A15, A22, A24	$ 2,148,645
904 Uncollectible Accounts	$ 342,271	$ 804,982	A20	$ 1,147,253
905 Miscellaneous Customer Accounts	$ 108,137	$ 1,093	A09	$ 109,230
Total Customer Accounts	$ 3,419,530	$ 1,074,054		$ 4,493,584
Customer Service and Informational				
907 Supervision (Customer Service)	$ 0	$ -		$ 0
908 Customer Assistance Expenses	$ 108,757	$ 2,046	A09	$ 110,803
909 Informational and Instructional Expenses	$ 10,182	$ -		$ 10,182
910 Miscellaneous Customer Service and Informational	$ 119,412	$ 1,294	A09	$ 120,706
Total Customer Service and Informational Expenses	$ 238,351	$ 3,340		$ 241,691
Sales Expenses				
911 Supervision (Sales)	$ 38,244	$ 719	A09	$ 38,963
912 Demonstrating and Selling Expenses	$ 19,039	$ 112,570	A09, A15, A23	$ 131,609
913 Advertising Expenses	$ 1,860	$ -		$ 1,860
916 Miscellaneous Sales Expenses	$ 7,198	$ -		$ 7,198
Total Sales Expenses	$ 66,342	$ 113,289		$ 179,631
Administrative and General				
920 Administrative and General Salaries	$ 3,080,586	$ 151,369	A09, A11, A15, A31	$ 3,231,955
921 Office Supplies and Expenses	$ 1,328,927	$ 77,367	A09, A25	$ 1,406,294
922 Administrative Expenses Transferred-Credit	$ (445,089)	$ -		$ (445,089)
923 Outside Services Employed	$ 3,882,261	$ 406,169	A09, A16, A35	$ 4,288,430
924 Property Insurance	$ 244,621	$ 201,980	A28	$ 446,601
925 Injuries and Damages	$ 959,797	$ (288,697)	A28, A29	$ 671,100
926 Employee Pensions and Benefits	$ 3,742	$ (22,501)	A12, A13	$ (18,759)
928 Regulatory Commission Expenses	$ 271,409	$ 144,547	A26, A34	$ 415,956
930.1 General Advertising Expenses	$ -	$ -		$ -
930.2 Miscellaneous General Expenses	$ 451,041	$ 187,046	A10	$ 638,087
931 Rents	$ 49,625	$ (33,227)	A30	$ 16,398
932 Maintenance of General Plant	$ 161,821	$ 1,101	A09	$ 162,922
Total A & G Expenses	$ 9,988,741	$ 825,154		$ 10,813,895
Total Operations and Maintenance Expense	**$ 20,084,895**	**$ 3,362,143**		**$ 23,447,038**
Depreciation and Amortization				
403 Depreciation Expense	$ 5,351,597	$ 192,508	A36	$ 5,544,105
403.1 Depr Exp for Asset Retirement Costs	$ -	$ -		$ -
Total Depreciation and Amortization	**$ 5,351,597**	**$ 192,508**		**$ 5,544,105**
Other Taxes				
408.1 Taxes Other than Income Taxes	$ 3,043,990	$ 13,149	A39, A40	$ 3,057,139
Total Other Taxes	**$ 3,043,990**	**$ 13,149**		**$ 3,057,139**

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSMENT SUMMARY
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

741	Maintenance of Structures & Improvements			
	Manufactured Gas Plant Expense	A17	$	(316,500)
			$	(316,500)
814	Operation Supervision and Engineering			
	Labor Adjustments for Existing Headcount	A09	$	58
			$	58
817	Lines Expense			
	Labor Adjustments for Existing Headcount	A09	$	26
			$	26
833	Maintenance of Lines			
	Labor Adjustments for Existing Headcount	A09	$	2
			$	2
835	Maintenance of Meas. & Reg. Station Equipment			
	Labor Adjustments for Existing Headcount	A09	$	25
			$	25
850	Operation Supervision and Engineering			
	Aging Workforce	A16	$	18,756
			$	18,756
856	Mains Expenses			
	Labor Adjustments for Existing Headcount	A09	$	1,370
	Aging Workforce	A16	$	17,093
	Pipeline Safety Act Costs	A18	$	109,335
	Pipeline Safety Act Deferral Amortization	A27	$	531,886
			$	659,684
857	Measuring and Regulating Station Expenses			
	Labor Adjustments for Existing Headcount	A09	$	1,171
			$	1,171
862	Maintenance of Structures and Improvements			
	Labor Adjustments for Existing Headcount	A09	$	56
	Distribution Maintenance	A19	$	218,200
			$	218,256
863	Maintenance of Mains			
	Labor Adjustments for Existing Headcount	A09	$	1,013
	Aging Workforce	A16	$	17,093
	Distribution Maintenance	A19	$	159,200
	Asset Management Program Costs	A32	$	65,687
			$	242,993
865	Maintenance of Measuring and Reg Station Equipment			
	Labor Adjustments for Existing Headcount	A09	$	312
			$	312
867	Maintenance of Other Equipment			
	Labor Adjustments for Existing Headcount	A09	$	49
			$	49
870	Operation Supervision and Engineering			
	Labor Adjustments for Existing Headcount	A09	$	6,042
	Aging Workforce	A16	$	18,756
			$	24,798
874	Mains and Services Expenses			
	Labor Adjustments for Existing Headcount	A09	$	6,992
	Aging Workforce	A16	$	51,279
			$	58,271
875	Measuring and Regulating Stations Expenses-General			
	Labor Adjustments for Existing Headcount	A09	$	1,370
			$	1,370
878	Meter and House Regulator Expenses			
	Labor Adjustments for Existing Headcount	A09	$	2,573
			$	2,573

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSMENT SUMMARY
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

879 Customer Installation Expenses			
Labor Adjustments for Existing Headcount	A09	$	10,341
Asset Management Program Savings	A33	$	(18,599)
		$	(8,258)
880 Other Expenses			
Labor Adjustments for Existing Headcount	A09	$	9,398
Training Expense	A14	$	37,088
Incremental Headcount	A15	$	28,280
Aging Workforce	A16	$	18,577
		$	93,343
885 Maintenance Supervision and Engineering			
Labor Adjustments for Existing Headcount	A09	$	5,652
Asset Management Program Costs	A32	$	12,444
		$	18,096
886 Maintenance of Structures and Improvements			
Labor Adjustments for Existing Headcount	A09	$	83
Distribution Maintenance	A19	$	218,200
		$	218,283
887 Maintenance of Mains			
Labor Adjustments for Existing Headcount	A09	$	8,893
Aging Workforce	A16	$	51,281
Distribution Maintenance	A19	$	41,000
		$	101,174
889 Maintenance of Measuring and Regulating Station Equipment-General			
Labor Adjustments for Existing Headcount	A09	$	599
		$	599
892 Maintenance of Services			
Labor Adjustments for Existing Headcount	A09	$	9,080
		$	9,080
893 Maintenance of Meters and House Regulators			
Labor Adjustments for Existing Headcount	A09	$	1,794
		$	1,794
894 Maintenance of Other Equipment			
Labor Adjustments for Existing Headcount	A09	$	351
		$	351
901 Supervision (Customer Accounts)			
Labor Adjustments for Existing Headcount	A09	$	3,422
Incremental Headcount	A15	$	10,844
		$	14,266
902 Meter Reading Expenses			
Labor Adjustments for Existing Headcount	A09	$	6,758
Meter Reading Costs	A21	$	26,001
		$	32,759
903 Customers' Billing and Accounting			
Labor Adjustments for Existing Headcount	A09	$	16,719
Incremental Headcount	A15	$	70,142
Contact Center Costs	A22	$	118,466
Miscellaneous Billing Costs	A24	$	15,627
		$	220,954
904 Uncollectible Accounts			
Uncollectible Accounts Expenses	A20	$	804,982
		$	804,982
905 Miscellaneous Customer Accounts			
Labor Adjustments for Existing Headcount	A09	$	1,093
		$	1,093
908 Customer Assistance			
Labor Adjustments for Existing Headcount	A09	$	2,046
		$	2,046

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSMENT SUMMARY
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

910 Miscellaneous Customer Service and Informational			
Labor Adjustments for Existing Headcount	A09	$	1,294
		$	1,294
911 Supervision (Sales)			
Labor Adjustments for Existing Headcount	A09	$	719
		$	719
912 Demonstrating and Selling Expenses			
Labor Adjustments for Existing Headcount	A09	$	133
Incremental Headcount	A15	$	40,702
Sales and Marketing Costs	A23	$	71,735
		$	112,570
920 Administrative and General Salaries			
Labor Adjustments for Existing Headcount	A09	$	41,876
Incentive Compensation Expense	A11	$	17,518
Incremental Headcount	A15	$	63,964
Changes in Cost Allocations	A31	$	28,011
		$	151,369
921 Office Supplies and Expenses			
Labor Adjustments for Existing Headcount	A09	$	1,226
Information Technology Costs	A25	$	76,141
		$	77,367
923 Outside Services Employed			
Labor Adjustments for Existing Headcount	A09	$	118
Aging Workforce	A16	$	237,576
Asset Charge	A35	$	168,475
		$	406,169
924 Property Insurance			
Property and Risk Insurance	A28	$	201,980
		$	201,980
925 Injuries and Damages			
Property and Risk Insurance	A28	$	(314,085)
Claims Expense	A29	$	25,388
		$	(288,697)
926 Employee Pensions and Benefits			
Pension Expense	A12	$	47,152
Postretirement Medical Expense	A13	$	(69,653)
		$	(22,501)
928 Regulatory Commission Expenses			
Rate Case Expense	A26	$	43,615
IURC Fee	A34	$	100,932
		$	144,547
930.2 Miscellaneous General Expenses			
Restricted Stock & Stock Option Expense	A10	$	187,046
		$	187,046
931 Rents			
Prior Headquarters Costs	A30	$	(33,227)
		$	(33,227)
932 Maintenance of General Plant			
Labor Adjustments for Existing Headcount	A09	$	1,101
		$	1,101
Total Operations and Maintenance Adjustments		**$**	**3,362,143**
403 Depreciation Expense			
Depreciation and Amortization	A36	$	192,508
		$	192,508
Total Depreciation and Amortization Adjustments		**$**	**192,508**

VECTREN SOUTH
GAS TARIFF
PRO FORMA ADJUSMENT SUMMARY
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

408.1 Taxes Other than Income Taxes			
Indiana Utility Receipts Tax	A39	$	126,036
Property Tax Expense	A40	$	(112,887)
		$	13,149
Total Other Taxes Adjustments		**$**	**13,149**

VECTREN SOUTH
GAS TARIFF
BALANCE SHEET
AS OF MARCH 31, 2006

	ASSETS	March 2006	March 2005
1	CURRENT ASSETS:		
2	Cash and cash equivalents	$ 229	$ 1,871
3	Accounts receivable, less reserves	51,009	47,085
4	Intercompany notes receivable	12,900	-
5	Accrued unbilled revenues	24,952	26,192
6	Receivable from other Vectren Co.	43	26
7	Materials and supplies - Fuel	15,436	10,414
8	Other	26,227	24,556
9	Allowance Inventory	124	262
10	Gas in underground storage - at average cost	-	3,009
11	Prepaid Gas Delivery Service	-	-
12	Prepayments	574	264
13	Prepaid Taxes	48	-
14	Recoverable fuel costs	2,223	-
15	Clearing Accounts	(177)	(1,004)
16	Other current assets	15,232	5,675
17		148,821	118,350
18	UTILITY PLANT:		
19	Original cost	1,469,209	1,408,797
20	Completed construction not classified	394,950	276,506
21	Utility plant held for future use	3,163	2,578
22	Construction work in progress	51,483	124,016
	Less - Accumulated depreciation		
23	and amortization	809,120	764,541
24		1,109,686	1,047,356
25	NONUTILITY PLANT AND OTHER INVESTMENTS		
26	Nonutility Property, Net	3,317	3,518
27	Acquisition Adjustment Hoosier	5,557	5,557
28	Investments in unconsolidated affiliates	150	150
29	Other Investments	6,630	9,798
30		15,654	19,022
31	DEFERRED CHARGES:		
32	Unamortized debt expense and premium	10,867	10,615
33	Demand side management programs	28,569	28,118
34	Accumulated deferred income tax	4,220	5,691
35	Other Regulatory assets	15,859	7,754
36	Miscellaneous Deferred Debits	1,122	157
37		60,637	52,335
38	Total Assets	$ 1,334,798	$ 1,237,064

VECTREN SOUTH
GAS TARIFF
BALANCE SHEET
AS OF MARCH 31, 2006

	LIABILITIES AND SHAREHOLDER'S EQUITY	March 2006	March 2005
1	CURRENT LIABILITIES:		
2	Accounts payable	$ 17,352	$ 19,342
3	Accounts payable to affiliated companies	9,182	5,892
4	Payables to other Vectren companies	9,453	8,153
5	Customer deposits and advance payments	8,112	7,424
6	Accrued taxes-Other	12,165	10,858
7	Accrued taxes-Income Taxes	6,019	7,397
8	Accrued interest to other Vectren companies	1,169	1,167
9	Accrued interest	2,256	2,179
10	Current deferred income taxes	4,784	1,353
11	Dividends payable	-	-
12	Tax collections payable	2,627	1,803
13	Accumulated provision for injuries and damages	966	430
14	Other current liabilities	12,719	17,991
15	Notes payable	619	-
16	Current maturities of long-term debt	-	-
17	Long-term debt subject to tender	-	-
18	Short-term borrowings to VUHI	38	151,712
19	Refundable gas costs	-	6,145
20		87,461	241,846
21	DEFERRED CREDITS:		
22	Regulatory Liabilities	60,020	52,392
23	Deferred income taxes	136,195	127,098
24	Accrued postretirement benefits other than pensions	16,484	16,389
25	Accrued pensions	9,613	10,232
26	Investment tax credit - net	8,920	10,401
27	Other	17,278	6,659
28		248,510	223,171
29	CAPITALIZATION:		
30	Common stock	273,263	128,258
31	Retained earnings	274,999	269,299
32	Accumulated comprehensive income	1,246	-
33	Common shareholder's equity	549,508	397,557
34	Bonds	228,165	228,165
35	Notes payable	-	-
36	Long-term borrowings with VUHI	223,368	148,699
37	Unamortized debt premium and discount - net	(2,214)	(2,375)
38	Preferred Stock	0	0
39		998,827	772,046
40	Total Liabilities and Shareholder's Equity	$ 1,334,798	$ 1,237,064

VECTREN SOUTH
GAS TARIFF
INCOME STATEMENT
12 MONTHS ENDING MARCH 31, 2006

		12 Months March 2006	12 Months March 2005
1	GAS		
2	Sales	$ 144,089	$ 107,551
3	Transportation	4,903	4,326
4	TOTAL GAS REVENUE	148,992	111,877
5	Cost of gas sold	112,709	78,066
6	MARGIN ON GAS OPERATIONS	36,284	33,812
7	OPERATING EXPENSES:		
8	Other operation	16,875	16,002
9	Maintenance	3,210	1,967
10	Transaction costs	-	-
11	Restructuring costs	-	-
12	Depreciation and amortization	5,352	5,170
13	Income taxes	2,418	1,918
14	Taxes other than income taxes	3,044	2,433
15		30,898	27,490
16	OPERATING INCOME (LOSS) (1)	5,385	6,321
17	OTHER INCOME (EXPENSE):		
18	AFUDC - equity	61	158
19	AFUDC - debt	113	271
20	Other - net	(84)	53
21	Interest income	10	3
22		100	486
23	INCOME (LOSS) BEFORE INTEREST AND OTHER CHARGES	5,485	6,808
24	INTEREST AND OTHER CHARGES:		
25	Interest on long-term debt	1,702	1,926
26	Interest on VUHI borrowings	1,983	1,922
27	Amortization of premium	135	149
28	Other interest on short-term borrowings	59	75
29		3,879	4,072
30	NET INCOME	$ 1,606	$ 2,736

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH – GAS)

IURC CAUSE NO. 43112

DIRECT TESTIMONY
OF
ROBERT C. SEARS
DIRECTOR OF REVENUE ADMINISTRATION

ON

BAD DEBT COST RECOVERY MATTERS

SPONSORING PETITIONER'S EXHIBIT RCS-1 THROUGH RCS-3

Direct Testimony of Robert C. Sears

Q. Please state your name and business address.

A. Robert C. Sears
Vectren Utility Holdings, Inc.
100 North Governor Street
Evansville, Indiana 47711

Q. What position do you hold with Petitioner Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South or Company")?

A. I am Director of Revenue Administration for Vectren Utility Holdings, Inc. ("VUHI"), the immediate parent company of Vectren South.

Q. Please describe your educational background.

A. I received a Bachelor of Science in electrical engineering technology from the University of Southern Indiana in 1986.

Q. Please describe your professional experience.

A. I have been employed with Vectren South since 1987 in a variety of positions. Previously, I was Director of Customer Service, with responsibility for customer service, billing and customer systems support for all VUHI utility operations. I have also held other positions including Manager of Energy Services, Manager of DSM Services, Residential and Commercial Marketing Supervisor and New Business Service Representative.

Q. What are your present duties and responsibilities as Director of Revenue Administration?

A. I am responsible for managing all aspects of revenue cycle operations including meter reading, billing, remittance, credit and collection, customer accounting, margin analysis, and customer billing system administration for all VUHI utilities including Vectren South. I am responsible for the direction and management of revenue assurance policies and procedures associated with the meter-to-cash cycle. Additionally, I assist in other areas concerning the development and administration of customer payment assistance programs.

Q. Have you previously testified before this Commission?

A. Yes. In Cause No. 42590 I provided testimony to support and explain the proposed Universal Service Program changes in support of the Joint Motion to Approve Amendment to Settlement Agreement.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony in this proceeding supports Vectren South's proposal to track the gas cost component of bad debt expense in the Company's quarterly Gas Cost Adjustment ("GCA") filings, as described by Petitioner's Witness Scott E. Albertson. I will explain the impact that gas market price volatility has had on Vectren South's level and recovery of bad debt expense, and will provide an overview of Vectren South's credit and collection performance.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

- Petitioner's Exhibit No. RCS-2 – "Selected Regulatory Mechanisms for Bad Debt Expense Recovery"
- Petitioner's Exhibit No. RCS-3 - "Vectren South Gas Historical Percentage of Net Write-Offs to Revenue"

Q. How has market price volatility impacted Vectren South's recovery of bad debt expense?

A. Market price volatility and high gas costs have increased customers' bills and created higher account balances which impact their ability to pay. The table below illustrates the impact of gas costs on the total bad debt expense, and on the percentage written off, during the test year in this proceeding and in the previous 12 month period.

	Period (12 Months Ending)		
	Mar-05	Mar-06	Variance(%)
Gas Costs	$6.01	$9.17	52.6%
Total Revenue	$109,861,846	$145,476,457	32.4%
Write-off $	$520,342	$673,475	29.%
Write-off %	0.61%	0.51%	-16.4%

The table above illustrates that even when bad debt management improves from a percentage of revenue perspective, a utility can still incur additional bad debt expense due to gas cost increases. Even though the percentage of write-offs to sales decreased for the 12 months ending March 31, 2006 as compared to the 12 months ending March 31, 2005, Vectren South's write-off expense increased by $151,133 during the same period, a 29% increase. The reason for this increase is the market price of gas. When gas prices increase, causing gas costs to comprise an even higher percentage of the total bill, customers typically have more difficulty paying those bills. This increase in the market price of gas results in an increase in Vectren South's write-off expense. The Company has no control over the market price of natural gas but is held financially responsible, under its current rate design, for the effects of higher market prices. Gas cost volatility is exactly why the GCA exists.

Q. Is the gas price impact on bad debt an industry-wide concern?

A. Yes. In October 2005, Citigroup Research, a division of Citigroup Global Markets, Inc., conducted a survey of 42 publicly-traded gas utilities in order to determine the impact of high natural gas prices on bad debt expense for 2005 and 2006. On page 4 of the report, it states, "Base rates generally include a fixed allowance to compensate utilities for bad debt expense. However, the continued rise in natural gas prices over the last several years has caused these expenses to rise leaving current allowances in base rates insufficient. Regulatory mechanisms such as rate trackers, gas accounting adjustments and expense adjustment mechanisms enable utilities to recover these costs without having to file a full blown rate case." Citigroup stated "we believe gas utilities have the opportunity to reshape the regulatory mechanics and regulators and state legislatures will have no choice but to look at alternative rate making. Id at p. 2." Citigroup found that about 43% of the utilities it surveyed have regulatory mechanisms that alleviate at least some bad debt concerns. The report listed thirteen states that have some form of regulatory mechanism in place to recover most or all bad debt. The report further stated that "the lack of trackers in the rest of the U.S. is discouraging given the trend in natural gas prices over the last several years. Id. at p. 5." Petitioner's Exhibit No. RCS-2 lists states which have approved mechanisms for recovery of components of bad debt expense, as well as the utilities with such mechanisms currently in effect.

In May 2006 the Janney Montgomery Scott, LLC Industry Report on High Commodity Prices in the Natural Gas Distribution Industry noted "rising uncollectibles (bad debt) as one of the issues that could impact gas distribution companies' financial performance." The report stated:

> Bad debt expenses are normally recovered as fixed costs in base rates. Higher than projected bad debt levels usually result from significant increases in gas commodity costs, which are outside of the LDC's control. Unless mitigated by a regulatory authority, the higher expense will reduce the LDC's return. Tariff provisions such as rate trackers, gas accounting adjustments, and expense adjustment mechanisms can help distributors recover additional costs and ensure that the LDC is made whole. Id. at p. 14.

In a June 2006 Special Comment Report from Moody's Investor Service stated:

> With natural gas prices expected to remain at high levels, local gas distribution companies (LDCs) face earnings and cash flow pressures as their customers increase conservation efforts. In addition, bad debt expense has increased as more customers face increasing difficulties in paying their bills. Bad debt expense has shown a steady average increase in each of the past four winters, tracking the increase in natural gas prices during the same period. LDCs in some states such as those located in North Carolina, had the good fortune of being able to recover the gas component of bad debt expense through their purchase gas adjustment (PGA) mechanism, thereby reducing the level of bad debt expense that the company had to absorb on their own. Id. at p. 1.

Q. How does Vectren South's bad debt expense percentage compare to that of other utilities?

A. Based upon the 2006 "AGA/EEI DataSource" (2005 annual results) Vectren South compares favorably to other gas utilities in terms of bad debt expense management. Vectren South's bad debt expense percentage is below the Gas and Combo utility average percentage for the last two years. Vectren South also includes the collection agency expense in the write-off calculation for "DataSource." Such costs are not consistently included by other respondents.

Q. Has Vectren South improved its bad debt expense percentage in recent years?

A. Vectren South has improved its bad debt expense percentage over the last few years by aggressively managing this expense. Petitioner's Exhibit No. RCS-3 shows the improvement that Vectren South has experienced in managing the percentage of net write-offs to revenue over the past 5 years. Even with such an improvement the actual bad debt expense itself has recently increased primarily due to gas costs. With higher gas costs, Vectren South will continue to be challenged to maintain its current level of performance as an increasing number of customers struggle to pay their bills because of these market driven costs. Vectren South has projected an increase in the percentage of net write-offs to revenue for 2006 due to these higher gas costs. Natural gas costs, which are beyond the Company's control, impact customers' ability to pay which results in a higher write-off of bad debt expense and applies additional pressure to maintain or improve the Company's level of write-offs (as a percentage of revenue).

Q. Please discuss the initiatives that Vectren South has implemented to aggressively manage customer bad debt expenses?

A. Vectren South has implemented a number of initiatives over the last few years aimed at controlling the level of uncollectible expense. These initiatives include engaging an outside firm (PAR 3) specializing in automated calling for payment management, implementing positive identification and credit verification upon account initialization, and requiring paid deposits from new customers failing to meet IURC approved deposit requirements as well as from customers with a previous non-payment history. Vectren South adjusted processes in 2003 to more effectively utilize our customer information system to identify customers with previous written off accounts that are requesting current service. In early 2006, Vectren South also engaged an outside firm to utilize our customer information system to identify existing customers with previous written off accounts and transfer the balance to the existing account. In addition, Vectren South implemented additional check payment capability in 2003 for customers. Customers can now pay a Vectren South bill on a no-fee basis via telephone to our contact center or on our website. Vectren South also provides the capability of taking payment via credit cards on a fee basis. Both the check and credit card capabilities provide customers with a delinquent account with alternative convenient methods of payment. This additional payment capability aids the customer that wants to pay a bill in order to avoid service disconnection resulting from non-payment. The Company also actively works with customers by providing assistance programs and payment arrangements to help them manage their utility bill in order to maintain utility service. The Company offers a Budget Bill program to assist customers with managing their utility bills. Vectren South also funds several assistance programs such as Fall Reconnection assistance, Residential Weatherization, Share the Warmth, Help Thy Neighbor Program and the Universal Service Program to assist income eligible customers with their energy bills. Vectren South is also proposing, as part of Cause No. 42943, energy efficiency and conservation programs to help customers reduce their total gas bill.

Vectren South also aggressively manages accounts and works with customers with overdue balances by actively contacting customers with past due bills and offering payment arrangements that allow those customers to make timely payment of past due amounts. When these efforts to help customers are unsuccessful, Vectren South is diligent in performing disconnections to minimize bad debt expense. Vectren South disconnection activity increased 6% in calendar year 2005 versus 2004 and has increased 7% year-to-date June 2006 versus year-to-date June 2005.

Q. If the proposed rate design is approved such that the gas cost component of bad debt expense is tracked in the GCA, what incentive does Vectren South have to control bad debt expense?

A. Vectren South has sufficient incentive to control bad debt, even under a rate design that tracks the gas cost component via the GCA. Base rates will include a margin component of bad debt under our proposal, that portion above the amount established in this and future base rate proceedings will still be at risk. Vectren South diligently manages bad debt expense related items and would continue to do so as a sound business practice as well as because it is in the best interest of customers. Further, Vectren South expects the Commission to continue to hold it accountable to manage bad debt expense in order to receive recovery of non-gas cost related bad debt expense in future general rate cases.

Q. Apart from the level of experience, are there other human considerations that must be considered in managing bad debt?

A. Yes, Vectren South does not unilaterally control the credit and collections policies that impact bad debt expense such as deposit requirements, disconnection moratoriums, payment arrangements, and the decision when a customer can be disconnected. Tracking of the uncontrollable gas cost component of bad debt expense in the GCA allows Vectren South and regulatory and governmental stakeholders to work together to determine the best balance of credit and collection rules and weigh both the short-term and long-term impact of these decisions on all customers.

Q. Please summarize your conclusions.

A. Actual recovery of bad debt expense under Vectren South's current rate design is impacted by market price volatility, weather and other factors outside the utility's control which can lead customers to use more or less gas than expected within a period, which in turn results in higher or lower bills impacting bad debt expense and bad debt expense recovery. Higher bills mean additional customers will struggle to pay their bills, ultimately resulting in increased bad debt expense. Changes in Commission rules such as the recently implemented customer deposit and disconnect rules, the economic conditions within Vectren South's service territory, and political reactions to high natural gas prices can all have an impact on a utility's ability to manage bad debt expense. These factors can create an even greater risk for utilities as regulatory and political stakeholders take actions in response to volatile gas prices which directly or indirectly impact bad debt expense.

Q. Does this conclude your direct testimony?

A. Yes, at this time.

Petitioners Exhibit No. RCS-2

Selected Regulatory Mechanisms for Bad Debt Expense Recovery

State	Regulatory Mechanism	Utilities Affected
Michigan	Bad Debt Tracker	DTE (MichCon)
Ohio	Bad Debt Tracker	NiSource, Vectren, Dominion
Tennessee	Bad Debt Tracker	AGL, Atmos, Piedmont
Kansas	Expense Adjustment Factor	Oneok
Maine	Expense Adjustment Factor	NiSource, Vectren, Dominion
Maryland	Expense Adjustment Factor	WGL Holdings
Massachusetts	Expense Adjustment Factor	Nisource, Keyspan, NSTAR
New Hampshire	Expense Adjustment Factor	Keyspan
Oregon	Expense Adjustment Factor	Northwest Natural
Rhode Island	Expense Adjustment Factor	Southern Union
Washington	Expense Adjustment Factor	Northwest Natural, Puget
Utah	Gas Cost Accounting Adjustment	Questar
Wyoming	Gas Cost Accounting Adjustment	Questar
North Carolina	Gas Cost Accounting Adjustment	Piedmont
Washington D.C.	Income-Eligible Discount	WGL Holdings
Texas	Expense Adjustment Factor	Atmos - Amarillo
New Jersey	Expense Adjustment Factor	South Jersey Gas, New Jersey Natural PSE&G, Elizabethtown Gas
Idaho	Expense Adjustment Factor	Avista
New York	Expense Adjustment Factor	Central Hudson Gas and Electric

Source: American Gas Association, Citigroup Investment Research, Moody's Investors Service, Vectren Research

Petitioners Exhibit No. RCS-3

Vectren South Gas Historical Percentage of Net Write-Offs to Revenue					
Period (12 Month Ending)					Five Year
Mar-02	Mar-03	Mar-04	Mar-05	Mar-06	Average
1.05%	1.00%	1.03%	0.61%	0.51%	0.74%

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH-GAS)

IURC CAUSE NO.________ 43112

DIRECT TESTIMONY
OF
PAUL R. MOUL

ON

COST OF EQUITY
FAIR RATE OF RETURN ON FAIR VALUE

SPONSORING PETITIONER'S EXHIBIT NO. PRM-2

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

d/b/a Vectren Energy Delivery Of Indiana, Inc.

(Vectren South-Gas)

Direct Testimony of Paul R. Moul

Table of Contents

GLOSSARY OF ACRONYMS AND DEFINED TERMS

ACRONYM	DEFINED TERM
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
FFO	Funds from Operations
FOMC	Federal Open Market Committee
g	Growth rate
GDP	Gross Domestic Product
IGF	Internally Generated Funds
IURC	Indiana Utility Regulatory Commission
Lev	Leverage modification
LT	Long Term
MLP	Master Limited Partnerships
MM	Modigliani and Miller
PUC	Public Utility Commission
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
v	represents the value that accrues to existing shareholders from selling stock at a price different from book value

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant of the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis and a recommendation concerning the appropriate rate of return that the Indiana Utility Regulatory Commission ("IURC" or the "Commission") should allow Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South-Gas" or the "Company") an opportunity to earn on its gas jurisdictional rate base devoted to public service. I will also address the fair rate of return applicable to the Company's fair value rate base. My analysis and recommendation are supported by the detailed financial data contained in Petitioner's Exhibit No. PRM-2, which is a multi-page document divided into thirteen (13) schedules. Additional evidence, in the form of appendices, follows my direct testimony. The items covered in these appendices provide additional detailed information concerning the explanation and application of the various financial models upon which I rely. My testimony is based upon my first hand knowledge of Vectren South consisting of information obtained from meetings with the Company's management and Company-specific data, which is widely disseminated within the financial community.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return on common equity for the Company in this case?

A. My conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity within a range of 11.50% to 12.00%. From this range, I recommend an 11.75% rate of return on common equity for the purpose of this case. As shown on Schedule 1, I have presented the weighted average cost of capital for the Company, as taken from the pre-filed direct testimony of Mr. Robert L. Goocher, the Company's Vice President and Treasurer. Calculations are also provided that include capital from non-investor provided sources typically used in the ratesetting process by the IURC. The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and provides the Company with the ability to attract capital on reasonable terms.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. The Company is a wholly-owned subsidiary of Vectren Utility Holdings, Inc. ("VUHI"), which in turn is a wholly-owned subsidiary of Vectren Corporation ("Vectren"). The common stock of Vectren is traded on the New York Stock Exchange. Vectren is a component of the S&P 400 Midcap Index.

The Company provides natural gas distribution service to approximately 112,000 customers in southwestern Indiana. Throughput to these customers in 2005 was represented by approximately 24% to residential customers, 14% to commercial customers, 62% to industrial customers. Industrial customers comprise just 77 customers, or less than one-tenth of one percent of the Company's customers. This means that the energy needs of a few customers can have a significant impact on the Company's operations.

The Company's flowing gas is provided by transportation arrangements with interstate pipelines, which it obtains through its agent ProLiance Energy. The Company supplements its flowing gas supplies with gas withdrawn from underground storage.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a natural gas utility, such as Vectren South-Gas. In this regard, I relied on four well-recognized measures of the cost of equity: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must provide a utility with the opportunity to cover its interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be adequate to attract capital in all market conditions, be commensurate with the risk to which the utility's capital is exposed, and support reasonable credit quality.

Q. What factors have you considered in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from my proxy group of eight natural gas companies. The proxy group consists of natural gas companies that: (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey, (iv) they have not recently cut or omitted their dividend, (v) they are not currently the target of a merger or acquisition, (vi) they operate with a weather normalization and/or decoupling feature to their tariff or have other similar features, and (vii) they have at least 70% of their assets subject to utility regulation. The companies in the proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Gas Group" throughout my testimony.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not separately measured the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company has become increasingly problematic. By employing group average data, rather than individual companies' analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

	Gas Group
DCF	10.20%
RP	11.70%
CAPM	12.36%
Comparable Earnings	15.30%
Average	12.39%
Median	12.03%
Mid-point	12.75%

Focusing upon the market model approaches of the cost of equity (i.e., DCF, RP and CAPM), the average equity return produced is 11.42% (10.20% + 11.70% + 12.36% = 34.26% ÷ 3). From all these measures, I recommend that the Commission set the Company's rate of return on common equity within the range of 11.50% to 12.00%, and to employ an 11.75% cost of equity to calculate its weight average cost of capital. The low end of my recommended range is supported principally by the market models, i.e., DCF, RP and CAPM, while the top end of the range is supported by all four methods shown above. The specific factors that uniquely impact the Company's risk profile will be described in the following section of my testimony, and the pre-filed direct testimony of Mr. Jerome A. Benkert, Jr., the Company's Executive Vice President and Chief Financial

Officer. My range of the cost of equity of 11.50% to 12.00% makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events.

I should note that at this time, the DCF model is providing atypical results. That is to say, the low DCF returns can be traced in part to the unfavorable investor sentiment for the gas companies. Indeed, the average Value Line Timeliness Rank for my Gas Group is "4," which places them in the below average category and signifies that they are relatively unattractive investments. Moreover, page 5 of Schedule 11 shows that the gas distribution companies are ranked 95 out of 98 industries for probable performance over the next twelve months. The significance of this low ranking is that performance for this group is expected to be subpar, thereby indicating that the DCF results will not provide a cost of equity indication that corresponds with the results of the other methods/models. Although I have not ignored the DCF results, I am recommending less reliance on DCF in this case.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of the natural gas utilities?

A. The new competitive, regulatory and economic risks facing gas utilities are different today than formerly. Market-oriented pricing, open access for gas transportation, and changes in service agreements mean that natural gas utilities have been operating in a more complex environment with time frames for decision-making considerably shortened. Of particular concern for the Company, the recent high prices and volatility in natural gas commodity prices has had a negative impact on its customers. Higher commodity prices mean higher customer bills, as the cost of delivered gas is recovered through the GCA mechanism. Higher and volatile gas costs may result in further declines in average use per existing customer and in fewer new customers selecting natural gas to meet their energy needs. The resulting high gas prices have also had an impact on the amount of and number of delinquent customer accounts.

As the competitiveness of the natural gas business increases, the risk also increases. With the availability of customer-owned transportation gas, along with delivery of uncertain volumes to dual-fuel customers, risk will continue to rise as large end users obtain for themselves the range of unbundled service offerings which are currently available from the interstate pipelines for the local distribution utilities.

Q. Does the Company face competition in its natural gas business?

A. Yes. The changes fostered by the Federal Energy Regulatory Commission's Order 636 have promoted competition among and between pipelines and distributors through bypass facilities and placed more responsibilities on local distribution companies, such as Vectren South-Gas, to manage the upstream acquisition and delivery functions both from a reliability and price perspective. The major problem is that the larger customers have made their own gas supply arrangements and the customers that remain sales customers tend to be lower load factor customers that tend to be more expensive to serve.

Q. How does the Company's throughput to industrial customers affect its risk profile?

A. The Company's risk profile is strongly influenced by natural gas sold/delivered to industrial customers. The throughput to the Company's industrial customers represents 62% of total throughput, although this class contains only 77 customers. Large volume users, which have traditionally used transportation service, also have the ability to bypass the Company' system. Success in this aspect of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from competitors. Moreover, external factors can also influence the Company's throughput to these customers which face competitive pressure on their operations from facilities located outside the Company's service territory.

Q. Please indicate how its construction program affects the Company's risk profile.

A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The rehabilitation of the Company's infrastructure represents a non-revenue producing use of capital. The Company had 279 miles of its distribution mains constructed of cast iron and unprotected steel pipe as of year-end 2005. Also, the Company expects to replace 5,108 of its services. The Company projects its construction expenditures will be over $56 million in the period 2006-2010. Over this five-year period, these capital expenditures will represent an approximate 51% ($56.1 million ÷ $110.9 million) increase in the net utility plant component of the Company's original cost rate base claim in this proceeding.

Q. Does your cost of equity analysis and recommendation take into account the revenue decoupling that the Company is proposing in this case and the continuation of the normal temperature adjustment ("NTA") that was implemented by the Company in October 2005?

A. Yes. Among other riders that the Company proposes to include in its tariff, the revenue decoupling and NTA are intended to separate revenues from variations in sales related to usage caused by variations in year-to-year weather conditions from the "normal" weather assumed in establishing rates in a test year context and by conservation efforts by the Company's customers. My cost of equity analysis that provides a range of 11.50% to 12.00% rate of return on common equity takes into account the Company's proposals.

Q. Do the LDCs included in your Gas Group already have tariff mechanisms similar to decoupling and the NTA?

A. Yes, and therefore my analysis already reflects the impacts of the decoupling and NTA on investor expectations through the use of market-determined models. All eight of the companies in my Gas Group already have some form of revenue stabilization mechanism, most of which are related to temperature variations, and one additional company has a rate design intended to mitigate the effect of declining use per customer. As such, the market prices of these companies' common equity reflect the expectations of investors related to a regulatory mechanism that adjust revenues for abnormal weather.

Other companies in the Gas Group also have been allowed to implement a variety of mechanisms to deal with issues such as infrastructure rehabilitation, bad debt expenses, and conservation expenditures by the LDCs. The trend in the industry is to stabilize the recovery of fixed costs which are unaffected by usage. The Company's proposed decoupling and continuation of the recently implemented NTA is designed to accomplish this.

Q. How do investors assess the risk to an LDC of variations in customer usage caused by weather?

A. Investors in a gas utility can only formulate reasonable expectations based upon normal weather, although achieved results may vary significantly from those expectations from year to year due to variations in weather. That is to say, a rational investor in a gas utility can only anticipate, and base his or her analyses on normal temperature conditions. The financial theory upon which the cost of equity is based recognizes that investors value their investments on a long-term basis covering a number of years, not just one year. For example, the DCF formula explicitly assumes a growth rate "approaching infinity." Additionally, as I will discuss later, analysts' forecasts of utilities' earnings and dividend growth, which investors take into account in making investment decisions, typically are provided on a five-year basis. Weather, by definition, is normal over the long-term or multi-year period, although it may vary significantly from year to year. Moreover, one of the standard models of the cost of equity (i.e., CAPM) suggests that there is no measurable effect on the cost of equity because weather represents a company-specific risk, which does not receive compensation in the CAPM. Therefore, the theories and models underlying my cost of capital analysis obviate the need for adjustments based upon short-term phenomena such as weather variations which have no long-term effect. Accordingly, over the long term, the investor required cost of capital or discount rate assumed for an investment in a gas utility would be the same either with or without a NTA.

That is not to say there are no benefits to the proposed decoupling and NTA. Variations in weather can significantly affect customers' bills and the Company's cash flow. Fluctuations in bad debt expense from year to year, which may also be driven in part by variations in weather, also affect the Company's cash flow. Therefore, the Company can be expected to realize a short-term benefit of improved or at least more predictable liquidity as a result of implementation of these riders. Indeed, the decoupling and NTA will remove some of the Company's cash flow variability, which would be viewed favorably by the credit rating agencies. As such, the decoupling and NTA would help the Company to sustain its credit ratings. These are beneficial impacts which will be most directly manifested at the credit quality level rather than the determination of the Company's cost of equity.

Q. How should the Commission respond to the issues facing the natural gas utilities and in particular Vectren South-Gas?

A. The Commission should recognize and take into account the heightened competitive environment in the natural gas business in determining the cost of capital for the Company and provide a reasonable opportunity for the Company to actually achieve its cost of capital. It should also recognize that the Company is subject to the risk related to earnings attrition even with decoupling, since other costs are rising each year but margins are flat with minor customer growth. This leaves the Company in the situation that its ability to earn the allowed return is in jeopardy even with decoupling.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors which bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and its required returns are described in Appendix C. For this purpose, I have utilized the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and the Gas Group.

Q. What are the components of the S&P public utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4. I have used this group as a broad-based measure of all types of utility companies.

Q. What criteria did you employ to assemble the Gas Group?

A. The Gas Group that I employed in this case includes companies that are (i) engaged in similar business lines, (ii) have publicly-traded common stock, (iii) are included in The Value Line Investment Survey, (iv) have revenue stabilization mechanisms in effect, (v) have not recently reduced their common dividend, (vi) are not currently the target of a merger or acquisition, and (vii) have at least 70% of their assets represented by regulated operations. The Gas Group members are identified on page 2 of Schedule 3.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the credit rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for the Company, the Gas Group, and the S&P Public Utilities?

A. Presently, the corporate credit rating ("CCR") for Vectren South is A- from Standard and Poor's Corporation ("S&P") and the Long Term ("LT") issuer rating is Baa1 from Moody's Investors Services ("Moody's"). The CCR designation by S&P and LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The average credit quality of the Gas Group is an A from S&P and A3 from Moody's. For the S&P Public Utilities, the average composite rating is BBB+ by S&P and Baa1 by Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for Vectren South, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3 and 4. The data cover the five-year period 2001-2005. For the purpose of my analysis, I have analyzed the historical results for Vectren South, the Gas Group and the S&P Public Utilities. I will highlight the important categories of relative risk as follows:

Size. In terms of capitalization, Vectren South is smaller than the average size of the Gas Group and the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for Vectren South and the Gas Group.

Market Ratios. Market-based financial ratios provide a partial indication of the investor-required cost of equity. If all other factors are equal, investors will require a higher return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[1]

There are no market ratios available for Vectren South because its stock is owned by Vectren. The five-year average price-earnings multiple was similar for the Gas Group and the S&P Public Utilities. The five-year average dividend yield was higher for the Gas Group, as compared to the S&P Public Utilities. The five-year average market-to-book ratio was higher for the Gas Group, as compared to the

---

[1] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 52.0% for Vectren South, 51.0% for the Gas Group and 39.5% for the S&P Public Utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.169 (2.2% ÷ 13.0%) for Vectren South, 0.067 (0.8% ÷ 12.0%) for the Gas Group, and 0.231 (2.5% ÷ 10.8%) for the S&P Public Utilities.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income).[2] The five-year average operating ratios were 80.8% for Vectren South, 88.1% for the Gas Group, and 84.6% for the S&P Public Utilities.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding AFUDC) was 4.12 times for Vectren South, 3.90 times for the Gas Group, and 2.68 times for the S&P Public Utilities.

---

[2] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of Allowance for Funds Used During Construction ("AFUDC") related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for Vectren South, the Gas Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 53.6% for Vectren South, 90.7% for the Gas Group, and 109.0% for the S&P Public Utilities.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[3] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line betas provided on page 2 of Schedule 3 -- .76 as the average for the Gas Group, and page 3 of Schedule 4 -- .95 as the average for the S&P Public Utilities. Keeping in mind that the utility industry has changed dramatically during the past five years, the systematic risk percentage is 80% (.76 ÷ .95) for the Gas Group using S&P Public Utilities' average beta as a benchmark.

Q. Please summarize your risk evaluation of Vectren South and the Gas Group.

A. Vectren South is smaller than the average size of the Gas Group and it has much weaker IGF to construction. Further, the Company has very substantial construction requirements for the future, and its throughput are highly influenced by

---

3 The procedure used to calculate the beta coefficient published by Value Line is described in Appendix I. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

industrial customers. Overall, the fundamental risk factors indicate that the Gas Group provides a conservative basis for measuring the Company's cost of equity.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships between Vectren South, the Gas Group and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I describe in Appendix C. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As noted in Appendix C, and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and have arrived at a range of the cost of equity of 11.50% to 12.00% for Vectren South-Gas.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Appendix D. I will summarize them here. The Discounted Cash Flow ("DCF") model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stocks consists of a current cash (dividend) yield and future price appreciation (growth) of the investment.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

As I describe in Appendix E, the DCF approach has other limitations that diminish its usefulness in the ratesetting process when the market capitalization diverges significantly from the book value capitalization. When this situation exists, the DCF method will lead to a misspecified cost of equity when it is applied to a book value capital structure.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended May 2006, the monthly dividend yields of the Gas Group are shown graphically on Schedule 5. The monthly dividend yields shown on Schedule 5 reflect an adjustment to the month-end prices to reflect the build up of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment). An explanation of this adjustment is provided in Appendix D.

For the twelve months ending May 2006, the average dividend yield was 3.89% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three- month periods were 4.02% and 4.03%, respectively. I have used, for the purpose of my direct testimony, a dividend yield of 4..02% for the Gas Group, which represents the six-month average yield. The use of this dividend yield will reflect current capital costs while avoiding spot yields.

For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different but generally accepted manners, and used the average of the three adjusted values as calculated in Appendix D. That adjusted dividend yield is 4.14% for the Gas Group.

Q. Please explain the underlying factors that influence investor's growth expectations.

A. As noted previously, investors are interested principally in the future growth of its investment (i.e., the price per share of the stock). As I explain in Appendix D, future earnings per share growth represents its primary focus because under the constant price-earnings multiple assumption of the DCF model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth. The variables that can be considered include: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis can also be formulated, which consists of internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. The internal growth rate can be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time. Hence, a fundamental growth rate analysis is duplicative of expected book value per share growth.

Growth can also be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begins to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing its capital gains expectations with its dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor expected growth.

Q. Before presenting your analysis of the growth rates that apply specifically to the Gas Group, can you provide an overview of the macroeconomic factors that influence investor growth expectations for common stocks?

A. Yes. As a preliminary matter, it is useful to view macroeconomic forecasts that influence stock prices. Forecast growth of the Gross Domestic Product ("GDP") can represent the starting point for this analysis. The GDP has both "product side" and "income side" components. The product side of the GDP is comprised of: (i) personal consumption expenditures; (ii) gross private domestic investment; (iii) net exports of goods and services; and (iv) government consumption expenditures and gross investment. On the income side of the GDP, the components are: (i) compensation of employees; (ii) proprietors' income; (iii) rental income; (iv) corporate profits; (v) net interest; (vi) business transfer payments; (vii) indirect business taxes; (viii) consumption of fixed capital; (ix) net receipts/payment to the rest of the world; and (x) statistical discrepancy. The "product side," (i.e., demand components) could be used as a long-term representation of revenue growth for public utilities. However, it is well known that revenue growth does not necessarily equal earnings growth. There is no basis to assume that the same growth rate would apply to revenues and all components of the cost of service, especially after the troublesome issues of employees' costs, insurance costs, high fuel costs, and environmental costs are worked-out in the long-term for public utilities. The earnings growth rates for utilities will be substantially affected by fluctuations in operating expenses and capital costs.

The long-term consensus forecast that is published semi-annually by the Blue Chip Economic Indicators ("Blue Chip") should be used as the source of macroeconomic growth. Blue Chip is a monthly publication that provides forecasts incorporating a wide variety of economic variables assembled from a panel of more than 50 noted economists from the banking, investment, industrial, and consulting sectors whose advice affects the investment activities of market participants. It is always preferable to use a consensus forecast taken from a large panel of contributors, rather than to rely upon one source that may not be representative of the types of information that have an impact on investor expectations. Indeed, Blue Chip is frequently quoted in The Wall Street Journal, The New York Times, Fortune, Forbes, and Business Week. Twice annually, Blue Chip provides long-range consensus forecasts. Based upon the March 10, 2006 issue of Blue Chip, those forecasts are:

Blue Chip Economic Indicators		
Year	Nominal GDP	Corporate Profits, Pretax
2008	5.3%	3.9%
2009	5.3%	4.6%
2010	5.2%	4.3%
2011	5.1%	5.1%
2012	5.2%	6.0%
Averages		
2007-11	5.2%	4.8%
2012-16	5.2%	5.7%

These forecasts show that the rate of growth in corporate profits will decelerate during the early part of the forecast period due to the run-up in interest rates that I will discuss later in my testimony. Subsequently, growth will accelerate later in the period. It is also indicated historically that the percentage change in corporate profits has been higher than the percentage change in GDP.[4]

Q. What company-specific data have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedules 6 and 7. The bar graph provided on Schedule 6 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Schedule 6, historical growth in earnings per share was in the range of 5.13% to 7.31% for the Gas Group. Negative growth rates reflected in the historical data provide no reliable guide to gauge investor expected growth for the future. Investor expectations encompass long-term positive growth rates and, as such, could not be represented by sustainable negative rates of change. Therefore, statistics that include negative growth rates should not be given any weight when formulating a composite growth rate expectation. The prospect of rate increases granted by regulators, the continued obligation to provide service as required by customers, and the ongoing

[4] Obviously, growth in corporate profits are negatively impacted during recessionary periods, but on average corporate profits have grown historically over two percentage points faster than GDP since the 1934.

growth of customers mandate investor expectations of positive future growth rates. Stated simply, there is no reason for investors to expect that a utility will wind up its business and distribute its common equity capital to shareholders, which would be symptomatic of a long-term permanent earnings decline. Although investors have knowledge that negative growth and losses can occur, its expectations include positive growth. Negative historic values will not provide a reasonable representation of future growth expectations because, in the long run, investors will always expect positive growth. Indeed, rational investors expect positive returns, otherwise they will hold cash rather than invest with the expectation of a loss.

Schedule 7 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, and Reuters/Market Guide and from the Value Line publication. IBES/First Call, Zacks, and Reuters/Market Guide represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and Reuters/Market Guide forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 7 for the Gas Group.

Although five-year forecasts usually receive the most attention in the growth analysis for DCF purposes, present market performance has been strongly influenced by short-term earnings forecasts. Each of the major publications provides earnings forecasts for the current and subsequent year. These short-term earnings forecasts receive prominent coverage, and indeed they dominate these publications. While the DCF model typically focuses upon long-run estimates of earnings, stock prices are clearly influenced by current and near-term earnings forecasts.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the DCF model?

A. Yes. In fact, it illustrates that the infinite form of the model contains an unrealistic assumption. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings (P-E) multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences the total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication signals that investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

Q. What specific evidence have you considered in the DCF growth analysis?

A. As to the five-year forecast growth rates, Schedule 7 indicates that the projected earnings per share growth rates for the Gas Group are 4.95% by IBES/First Call, 5.17% by Zacks, 4.89% by Reuters/Market Guide, and 5.56% by Value Line. The Value Line projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 5.56%) than the dividends per share (i.e., 4.06%), which indicates a declining dividend payout ratio for the future. As indicated earlier, and in Appendix E, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What conclusion have you drawn from these data?

A. Although ideally historical and projected earnings per share and dividends per share growth indicators would be used to provide an assessment of investor growth expectations for a firm, the circumstances of the Gas Group mandate that the greater emphasis be placed upon projected earnings per share growth. The massive restructuring of the utility industry suggests that historical evidence alone does not represent a complete measure of growth for these companies. Rather, projections of future earnings growth provide the principal focus of investor expectations. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is forecasts of earnings per share growth. Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Reuters/Market Guide, and Value Line, represents a reasonable assessment of investor expectations.

It is appropriate to consider all forecasts of earnings growth rates that are available to investors. In this regard, I have considered the forecasts from IBES/First Call, Zacks, Reuters/Market Guide and Value Line. The IBES/First Call, Zacks, and Reuters/Market Guide growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, and Reuters/Market Guide estimates are obtained from the Internet and are widely available to investors free-of-charge. First Call is probably quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries.

With the repeal of the 1935 Public Utility Holding Company ("PUHC") act, merger and acquisition ("M&A") activity, which already has been prevalent in the utility industry, is expected to accelerate. Acquisitions are usually accomplished at premiums offered to induce stockholders to sell its shares. These premiums create a ripple effect on the stock prices of all utilities, just like a rising tide lifts all boats. Due to M&A activity, there has been a run-up of the stock prices for some utility companies. With these elevated stock prices, dividend yields fall, and without some adjustment to the growth component of the DCF model, the results become unduly depressed by reference to alternative investment opportunities – such as public utility bonds. There are three remedies available to deal with these potentially anomalous DCF results: (i) an adjustment to the DCF model to reflect the divergence of market capitalization and the book value capitalization, (ii) the use of a growth component in the DCF model which is at the high end of the range, and (iii) supplementing the DCF results with other measures of the cost of equity.

The forecasts of earnings per share growth as shown on Schedule 7 provide a range of growth rates of 4.89% to 5.56%. To those company-specific growth rates, consideration must be given to long-term growth in corporate profits. While the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.25% is within the array of earnings per share growth rates shown by the analysts' forecasts and the forecast growth in overall corporate profits. The Value Line forecast of dividend per share growth is inadequate in this regard due to the forecast decline in the dividend payout that I previously described. As previously indicated, the restructuring and consolidation now taking place in the utility industry, will provide additional risks and opportunities as the utility industry successfully adapts to the new business environment. These changes in growth fundamentals will undoubtedly develop beyond the next five years typically considered in the analysts' forecasts that will enhance the growth prospects for the future. As such, a 5.25% growth rate will accommodate all these factors.

Q. Does the sum of the dividend yield and growth rate provide a complete representation of the cost of equity?

A. No.

Q. Please explain why.

A. As demonstrated in Appendix D, the divergence of stock prices from book values creates a conflict when the results of a market-derived cost of equity are applied to the common equity account measured at book value, which is the measure used in calculating the weighted average cost of capital. This is the situation today where the market price of stock exceeds its book value for most utilities. This divergence of price and book value creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value.

If regulators rely upon the results of the DCF (which are based on the market price of the stock of the companies analyzed) and apply those results to book value, the resulting earnings will not produce the level of required return specified by the model when market prices vary from book value. This is to say, such distortions tend to produce DCF results that understate the cost of equity to the regulated firm when using book values. This shortcoming of the DCF has persuaded one regulatory agency to adjust the cost of equity upward to make the return consistent with the book value capital structure. The Pennsylvania Public Utility Commission in its Order entered December 22, 2004 involving PPL Electric Utilities Corporation at Docket No. R-00049255 acknowledged that an adjustment to the DCF results was required to make the return consistent with the book value capital structure. In that decision, the Pennsylvania PUC provided PPL (a wires-only electric delivery utility) with an additional 45 basis points to the simple DCF derived cost of equity for the financial risk difference related to the divergence of the market capitalization from the book value capitalization. Similar provisions were made by the Pennsylvania PUC in its decisions dated January 10, 2002 for Pennsylvania-American Water Company at Docket No. R-00016339; dated August 1, 2002 for Philadelphia Suburban Water Company in Docket No. R-00016750; dated January 29, 2004 for Pennsylvania American Water Company at Docket No. R-00038304 (affirmed by the Commonwealth Court on November 8, 2004); and dated August 5, 2004 for Aqua Pennsylvania, Inc. at Docket No. R-00038805. It must be recognized that in order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate cannot be used without modification. As I will explain later in my testimony, the DCF model can be modified to account for differences in risk attributed to changes in financial leverage when market prices and book values diverge.

Q. Is your leverage adjustment dependent upon the market valuation or book valuation from an investor's perspective?

A. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The DCF formula is derived from the standard valuation model: P = D/ (k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P+g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the ratesetting process utilizes the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Since the ratesetting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. My leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book are not on point. My leverage adjustment deals with the issue of financial risk and is not intended to transform the DCF result to a book value return through a market-to-book adjustment.

Further, as noted previously, the high market prices of gas utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on equity that exceeds its cost of equity. Stock prices above book value are common for utility stocks, and indeed non-regulated stock prices exceed book values by even greater margins. In this regard, according to the Barron's issue of June 19, 2006, the major market indices' market-to-book ratios are well above unity. Utility stocks trade at a multiple of 2.58 times book value which is below the market multiple of other indices. For example, the S&P 500 index trades at 3.02 times book value, the S&P Industrial index is at 3.48 times book value, and the

Dow Jones Industrial index is at 3.28 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of its cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true that when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. What are the implications of a DCF derived return that is related to market value when the results are applied to the book value of a utility's capitalization?

A. The capital structure ratios measured at the utility's book value show more financial leverage, and hence higher risk, than the capitalization measured at its market values. Please refer to Appendix E for the comparison. This means that a market-derived cost of equity, using models such as DCF and CAPM, reflects a level of financial risk that is different from that shown by the book value capitalization. Hence, it is necessary to adjust the market-determined cost of equity upward to reflect the higher financial risk related to the book value capitalization used for ratesetting purposes. Failure to make this modification would result in a mismatch of the lower financial risk related to market value used to measure the cost of equity and the higher financial risk of the book value capital structure used in the ratesetting process. That is to say, the cost of equity for the Gas Group that is related to the 53.22% common equity ratio using book value has higher financial risk than the 66.53% common equity ratio using market values. Because the ratesetting process utilizes the book value capitalization, it is necessary to adjust the market-determined cost of equity for the higher financial risk related to the book value of the capitalization.

Q. How is the DCF-determined cost of equity adjusted for the financial risk associated with the book value of the capitalization?

A. In pioneering work, Nobel laureates Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that as the borrowing of a firm increases, the expected return on stockholders' equity also increases. This principle is incorporated into my leverage adjustment which recognizes that the expected return on equity increases to reflect the increased risk associated with the higher financial leverage shown by the book value capital structure, as compared to the market value capital structure that contains lower financial risk. Modigliani and Miller proposed several approaches to quantify the equity return associated with various degrees of debt leverage in a firm's capital structure. These formulas point toward an increase in the equity return associated with the higher financial risk of the book value capital structure. As detailed in Appendix E, the Modigliani and Miller theory shows that the cost of equity increases by 0.61% (10.00% - 9.39%) when the book value of equity, rather than the market value of equity, is used for ratesetting purposes.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As explained previously, I have utilized a six-month average dividend yield ("D_1 /P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g ") previously developed. The DCF also includes the leverage modification ("lev.") required when the book value equity ratio is used in determining the weighted average cost of capital in the ratesetting process rather than the market value equity ratio related to the price of stock. The cost of equity must also include an adjustment to cover flotation costs ("flot.").

Q. Aside from the evidence on flotation application to utilities generally, what has been the experience for the Company?

A. The factor used to develop the modification that would account for the flotation costs adjustment is provided in Schedule 8 and Appendix E. In addition, Vectren Corporation, on behalf of its subsidiaries including SIGECO, have issued stock directly to the public and has incurred flotation costs. Details regarding the 2001 and 2003 common stock issues by Vectren are shown below:

Date of Offering	2/8/2001	Percent of Offering	8/7/2003	Percent of Offering
No. of shares offered (000)	5,500		6,500	
Dollar amt. of offering ($000)	$ 116,985		$ 148,265	
Price to public	$ 21.270		$ 22.810	
Underwriter's discounts and commission	$ 0.740	3.5%	$ 0.798	3.5%
Gross Proceeds	$ 20.530		$ 22.012	
Estimated company issuance expenses	$ 0.077	0.4%	$ 0.046	0.2%
Net proceeds to company per share	$ 20.453	3.9%	$ 21.966	3.7%

From the data shown above, the actual experience for stock sales by Vectren shows that flotation costs represent 3.7% to 3.9% of the offering price to the public. Therefore, a flotation costs adjustment must be applied to the DCF result (i.e., “k”) that provides an additional increment to the rate of return on equity (i.e., “K”).

Q. What DCF cost rate have you calculated?

A. The resulting DCF cost rate is:

	D_1/P_0	+	g	+	$kv.$	=	k	x	$flot.$	=	K
Gas Group	4.14%	+	5.25	+	0.61%	=	10.00%	x	1.02%	=	10.20%

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.20% (10.20% - 10.00%) to the rate of return on common equity for the Gas Group. In my opinion, this adjustment is reasonable for reasons explained in Appendix F. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings multiples do not remain constant.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Appendix H. I will summarize them here. With this method, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, a 6.50% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds. As I will subsequently show, the Moody's index and the Blue Chip forecasts support this figure.

The historical yields for long-term public utility debt are shown graphically on page 1 of Schedule 9. For the twelve months ended May 2006, the average monthly yield on Moody's A-rated index of public utility bonds was 5.81%. For the six and three-month periods ending May 2006, the yields were 6.01% and 6.23%, respectively.

Q. What are the implications of emphasizing recent data taken from a period of relatively low interest rates?

A. When interest rates rise from its current low levels, the overall cost of capital and cost of equity determined from recent data will understate future capital costs. Although it is always possible that interest rates could move lower, this possibility is out-weighed by the prospect of higher future interest rates. That is to say, there is more potential for higher rather than lower interest rates when the beginning point in the process contains low interest rates.

The low interest rates in 2003-'04 were, in part, the product of the Federal Open Market Committee ("FOMC") policy, which is now in transition. Indeed, on June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, June 30, 2005, August 9, 2005, September 20, 2005, November 1, 2005, December 13, 2005, January 31, 2006, March 28, 2006, May 10, 2006, and June 29, 2006, the FOMC increased the Fed Funds rate in seventeen 25 basis point increments. These policy actions, which have brought the Fed Funds rate to 5.25%, are widely interpreted as part of the process of moving toward a more neutral range for monetary policy. While short-term rates have increased significantly over the past twenty-one months, long-term rates have not moved similarly. This means that there has been a flattening of the yield curve. There is the potential for higher long-term interest rates, in the situation where the yield curve regains its normal upward slope as maturities are lengthened, and when short-term rates remain at current levels.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe above and in Appendix G. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on July 1, 2006, and the yield spread of 1.00% that I describe in Appendix G and Schedule 9. For comparative purposes, I have also shown the Blue Chip of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

Year	Quarter	Corporate Aaa-rated	Corporate Baa-rated	30-Year Treasury	A-rated Public Utility Spread	A-rated Public Utility Yield
2006	Second	6.0%	6.9%	5.2%	1.0%	6.2%
2006	Third	6.2%	7.1%	5.3%	1.0%	6.3%
2006	Fourth	6.3%	7.2%	5.4%	1.0%	6.4%
2007	First	6.3%	7.2%	5.4%	1.0%	6.4%
2007	Second	6.3%	7.2%	5.4%	1.0%	6.4%
2007	Third	6.2%	7.1%	5.3%	1.0%	6.3%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its June 1, 2006 publication, the Blue Chip published forecasts of interest rates are reported to be:

Year	Blue Chip Financial Forecasts Corporate Aaa-rated	Blue Chip Financial Forecasts Corporate Baa-rated	Blue Chip Financial Forecasts 30-Year Treasury	A-rated Public Utility Spread	A-rated Public Utility Yield
2007	6.4%	7.2%	5.5%	1.0%	6.5%
2008	6.3%	7.2%	5.5%	1.0%	6.5%
2009	6.3%	7.2%	5.5%	1.0%	6.5%
2010	6.2%	7.0%	5.3%	1.0%	6.3%
2011	6.3%	7.2%	5.4%	1.0%	6.4%
Averages					
2007-11	6.3%	7.2%	5.4%	1.0%	6.4%
2012-16	6.5%	7.3%	5.6%	1.0%	6.6%

Given these forecast interest rates, a 6.50% yield on A-rated public utility bonds represents a reasonable expectation.

Q. What equity risk premium have you determined for public utilities?

A. Appendix G provides a discussion of the financial returns that I relied upon to develop the appropriate equity risk premium for the S&P Public Utilities. I have calculated the equity risk premium by comparing the market returns on utility stocks and the market returns on utility bonds. I chose the S&P Public Utility index for the purpose of measuring the market returns for utility stocks because it is intended to represent firms engaged in regulated activities and today is comprised of electric companies and gas companies. The S&P Public Utility index is more closely aligned with these groups than some broader market indexes, such as the S&P 500 Composite index. The S&P Public Utility index is a subset of the overall S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of judgment in establishing the risk premium for public utilities. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Gas Group.

Q. What equity risk premium for the S&P Public Utilities have you determined for this case?

A. To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values set forth on page 2 of Schedule 10, the indicated risk premiums for the various time periods analyzed are 5.17% (1928-2005), 6.05% (1952-2005), 5.19% (1974-2005), and 5.20% (1979-2005). The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals and removes some of the more distant data from the analysis.

Q. Do you have further support for the selection of the time periods used in your equity risk premium determination?

A. Yes. First, the terminal year of my analysis presented in Schedule 10 represents the returns realized through 2005. Second, the selection of the initial year of each period was based upon the events that I described in Appendix H. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the deregulation of the financial markets. As such, additional data are merely added to the earlier results when they become available, clearly showing that the periods chosen were not driven by the desired results of the study.

Q. What conclusions have you drawn from these data?

A. Using the summary values provided on page 2 of Schedule 10, the 1928-2005 period provides the lowest indicated risk premium, while the 1952-2005 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.20% (5.19% + 5.20% = 10.39% ÷ 2) is shown from data covering the periods 1974-2005 and 1979-2005. Therefore, 5.20% represents a reasonable risk premium for the S&P Public Utilities in this case. As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Gas Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals between the Gas Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 5.00% represents a reasonable common equity risk premium in this case. This represents approximately 96% (5.00% ÷ 5.20% = 0.96) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Gas Group compared to the S&P Public Utilities.

Q. What common equity cost rate would be appropriate using this equity risk premium and the yield on long-term public utility debt?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). To that cost must be added an adjustment for common stock financing costs ("flot."). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*	+	*flot.*	=	*K*
Gas Group	6.50%	+	5.00%	=	11.50%	+	0.20%	=	11.70%

CAPITAL ASSET PRICING MODEL

Q. How have you used the Capital Asset Pricing Model to measure the cost of equity in this case?

A. I have used the Capital Asset Pricing Model ("CAPM") in addition to my other methods. As with other models of the cost of equity, the CAPM contains a variety of assumptions that I discuss in Appendix H. Therefore, this method should be used with other methods to measure the cost of equity, as each will complement the other and will provide a result that will alleviate the unavoidable shortcomings found in each method.

Q. What are the features of the CAPM as you have used it?

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Appendix I. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities. As such, to calculate the CAPM it is necessary to employ firms with traded stocks. In this regard, I performed a CAPM calculation for the Gas Group. In contrast, my Risk Premium approach also considers industry- and company-specific factors because it is not limited to measuring just systematic risk. As a consequence, the Risk Premium approach is more comprehensive than the CAPM. In addition, the Risk Premium approach provides a better measure of the cost of equity because it is founded upon the yields on corporate bonds rather than Treasury bonds.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 1 of Schedule 11, the average beta is .76 for the Gas Group.

Q. What betas have you used in the CAPM determined cost of equity?

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM unless those betas are applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book value capital structure, the Value Line betas have been unleveraged and releveraged for the common equity ratios using book values. This adjustment has been made with the formula:

$$\beta l = \beta u\ [1 + (1 - t)\ D/E + P/E]$$

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and therefore are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at its market values, the beta would become .57 for the Gas Group if it employed no leverage and was 100% equity financed. With the unleveraged beta as a base, I calculated the leveraged beta of .90 for the Gas Group associated with book value capital structure.

Q. What risk-free rate have you used in the CAPM?

A. For reasons explained in Appendix F, I have employed the yields on 20-year Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratesetting process. As shown on pages 2 and 3 of Schedule 11, I provided the historical yields on Treasury notes and bonds. For the twelve months ended May 2006, the average yield was 4.75%, as shown on page 3 of that schedule. For the six- and three-months ended May 2006, the yields on 20-year Treasury bonds were 4.93% and 5.16%, respectively. As shown on page 4 of Schedule 11, forecasts published by Blue Chip on July 1, 2006 indicate that the yields on long-term Treasury bonds are expected to be in the range of 5.3% to 5.4% during the next six quarters. The longer term forecasts described previously show that the yields on Treasury bonds will average 5.4% from 2007 through 2011 and 5.6% from 2012 to 2016. For reasons explained previously, forecasts of interest rates should be emphasized at this time. Hence, I have used a 5.50% risk-free rate of return for CAPM purposes.

Q. What market premium have you used in the CAPM?

A. As developed in Appendix I, the market premium is developed by averaging historical market performance (i.e., 6.5%) and the forecasts (i.e., 6.04%). For the historically based market premium, I have used the arithmetic mean. I am aware that the Commission has expressed its preference for considering both the arithmetic mean and the geometric mean. So if that approach is to be taken, much more weight should be placed on the arithmetic mean because it is the correct measure in the single-period model specification of the CAPM. The resulting market premium is 6.27% (6.5% + 6.04% = 12.54% ÷ 2), which represents the average market premium using historical and forecast data.

Q. Are there adjustments to the CAPM results that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. There would be an understatement of a firm's cost of equity with the CAPM unless the size of a firm is considered. That is to say, as the size of a firm decreases, its risk, and hence its required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs then otherwise similar larger firms (see Fundamentals of Financial Management, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. In this regard, Gas Group has an average market capitalization of its equity of $1,513 million, which would make them a large cap portfolio. However, Vectren Corporation has a market capitalization of just $2,064 million, which would place it in the fifth decile according to the size of the companies traded on the NYSE, AMEX, and NASDAQ. Vectren can be viewed in the context of a portfolio of mid-cap companies, and is included in the S&P midcap index. The midcap market capitalization would indicate a size premium of 1.02% for Vectren. Absent such an adjustment, the CAPM would understate the required return. My size adjustment is very conservative because the market capitalization of Vectren South by itself would be smaller than the mid-cap category described above and, therefore, is entitled to a larger size premium than I have used.

Q. What CAPM result have you determined using the CAPM?

A. Using the 5.50% risk-free rate of return, the leverage adjusted beta of .90 for the Gas Group, the 6.27% market premium, and the flotation cost adjustment developed previously, the following result is indicated.

	Rf	+	*ß*	x (	*Rm-Rf*	) +	*size*	=	*k*	+	*flot.*	=	*K*
Gas Group	5.50%	+	0.90	x (	6.27%	) +	1.02%	=	12.16%	+	0.20%	=	12.36%

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The technical aspects of my Comparable Earnings approach are set forth in Appendix I. In order to identify the appropriate return on equity for a public utility, it is necessary to analyze returns experienced by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided. To avoid circularity, it is essential that returns achieved under regulation not provide the basis for a regulated return. Because regulated firms must compete with non-regulated firms in the capital markets, it is appropriate to view the returns experienced by firms which operate in competitive markets. One must keep in mind that the rates of return for non-regulated firms represent results on book value actually achieved, or expected to be achieved, because the starting point of the calculation is the actual experience of companies that are not subject to rate regulation. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the

> convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.... The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

Therefore, it is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

There are two avenues available to implement the Comparable Earnings approach. One method would involve the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry would serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms. As such, this approach to Comparable Earnings avoids the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. Rather, it provides an indication of an earnings rate derived from non-regulated companies that are subject to competition in the marketplace and not rate regulation. Because, regulation is a substitute for competitively-determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. This is because returns realized by non-regulated firms have become increasingly relevant with the current risk profile of the public utility business. Moreover, the rate of return for a regulated public utility must be competitive with returns available on investments in other enterprises having corresponding risks, especially in a more global economy.

To identify the comparable risk companies, the Value Line Investment Survey for

Windows was used to screen for firms of comparable risks. The Value Line Investment Survey for Windows includes data on approximately 1700 firms. Excluded from the selection process were companies incorporated in foreign countries and master limited partnerships (MLPs).

Q. How have you implemented the Comparable Earnings approach?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from the Value Line Investment Survey for Windows that have six categories (see Appendix I for definitions) of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The identities of companies comprising the Comparable Earnings group and its associated rankings within the ranges are identified on page 1 of Schedule 12.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 12 because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Finally, because many of the comparability factors, as well as the published returns, are used by investors for selecting stocks, and to the extent that investors rely on the Value Line service to gauge its returns, it is, therefore, an appropriate database for measuring comparable return opportunities.

Q. What data have you used in your Comparable Earnings analysis?

A. I have used both historical realized returns and forecast returns for non-utility companies. As noted previously, I have not used returns for utility companies so as to avoid the circularity that arises from using regulatory influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization because the nature of the analysis relates to book value. Hence, Comparable Earnings does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. The historical rate of return on book common equity was 15.6% using the median value as shown on page 2 of Schedule 12. The forecast rates of return as published by Value Line are shown by the 15.0% median values also provided on page 2 of Schedule 12.

Q. What rate of return on common equity have you determined in this case using the Comparable Earnings approach?

A. The average of the historical and forecast median rates of return is:

	Historical	*Forecast*	*Average*
Comparable Earnings Group	15.60%	15.00%	15.30%

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion concerning the Company's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that the reasonable cost of common equity is within the range of 11.50% to 12.00% for the Company. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

FAIR RATE OF RETURN ON FAIR VALUE

Q. Have you also considered what would represent a fair return on the fair value of the Company's property?

A. Yes. Indiana ratesetting principles require that rates provide the utility with an opportunity to earn a fair rate of return on the fair value of its property used to provide utility service. Therefore, I have also performed a fair value analysis.

Q. In your opinion, what would be an appropriate fair value rate base for the Company?

A. In my opinion, it would be appropriate to give weight to both the replacement cost new less depreciation ("Replacement Cost") and the original cost less depreciation ("Original Cost") of the Company's utility property. In particular, I have derived a weighted fair value rate base by giving 47.05% weight to Replacement Cost and 52.95% weight to Original Cost. These relative weights were determined from the capital structure ratios calculated by Vectren South Witness Robert L. Goocher, as shown on page 1 of Petitioner's Exhibit RLG-2. The 47.05% weight assigned to the Replacement Cost value represents the Company's common equity ratio. The weight assigned to the Original Cost represents the remaining components of the Company's ratesetting capital structure. This method represents a compromise approach that is intended to make sure that, at a minimum, the Company gets the benefit of the appreciation in value of its assets to the extent they were financed by the common equity investor.

Q. What amount did you use for the Replacement Cost of the property?

A. My starting point was the replacement cost less depreciation valuation of the Company's utility plant in service as of March 31, 2006 performed by Vectren South Witness John P. Kelly. Mr. Kelly states in his testimony that his methodology gives consideration to current construction costs technology. In order to make sure the effect of technological change on replacement costs was not understated, I asked Mr. Kelly to make an additional downward adjustment of 2.25% per year to the depreciable plant accounts other than mains and services. This resulted in an adjusted Replacement Cost value of $172,761,514 as shown on page 1 of Petitioner's Exhibit JPK-3. I then added the following amounts that are included in the Company's proposed Original Cost rate base (Petitioner's Exhibit MSH-3, page 2 of Adjustment A42)) but which were not included in Mr. Kelly's valuation: materials and supplies ($605,003), stores expense ($402,626), and gas in underground storage ($6,571,368). This resulted in a total Replacement Cost rate base of $180,340,511.

Q. Why did you recommend a technology adjustment of 2.25%?

A. Mr. Kelly advised me that the average age of the current cost dollars invested in the Company's gas plant was approximately 20 years (precisely, 19.64 years). In my opinion, a reasonable adjustment for technological change would reflect productivity advances over that period of time (1986 to 2006). The Bureau of Labor Statistics ("BLS") index of labor productivity (output per hour worked) provides the basis for calculating the following measures of productivity over this time frame:

Bureau of Labor Statistics
Measures of Productivity
1986 to 2006 (First Quarter)

Sector : Business	2.21%
Sector : Nonfarm Business	2.15%
Sector : Nonfinancial Corporations	2.47%

From this information, I concluded that a productivity factor of approximately 2.25% would be a reasonable measure of the impact of technological change.

Q. What amount did you use for the Original Cost of the Company's property?

A. I used the amount of $118,480,432, which is the Original Cost rate base supported by Petitioner's Witness Ms. M. Susan Hardwick as shown on Petitioner's Exhibit MSH-3, page 2 of Adjustment A42.

Q. What weighted fair value rate base did you derive from this data?

A. Using the methodology described above, I developed a fair value rate base of $147,585,599 as follows:

Valuation Method	Amount	Weight	Weighted Amount
Replacement Cost	$ 180,340,511	47.05%	$ 84,850,210
Original Cost	$ 118,480,432	52.95%	$ 62,735,389
Fair Value		100.00%	$ 147,585,599

Q. In your opinion, what would be a fair rate of return on the fair value of the Company's rate base?

A. As shown by Mr. Kelly's testimony and exhibits, the current value of the Company's rate base exceeds the original cost of these assets. This is due mainly to the inflation that has occurred since the property was devoted to public service. The argument is sometimes made that, if inflation is reflected in a utility's property values, then inflation should be removed from the utility's cost of capital. I have reservations concerning this theory. First, the inflation deduction theory provides a mismatch of the historical inflation reflected in property values and the prospective inflation expectations reflected in capital costs as established by investors. Further, under fair value ratesetting the utility and its equity owners should benefit from the appreciation in the value of the utility's property since its installation date. Reducing the rate of return applicable to the fair value rate base below the cost of capital has the effect of depriving the equity owner of at least some (and potentially all) of this benefit. However, setting aside these concerns, I have calculated an 7.27% rate of return on fair value that reflects the removal of inflation from the common equity cost rate used in the determination of the Company's cost of capital. The rate of return is shown on Schedule 13.

Q. How have you calculated the 7.27% fair rate of return applicable to the fair value rate base?

A. In order to synchronize the historical inflation adjustment with the Company's rate base, I have calculated a 3.05% historical inflation rate covering the years 1986 through 2006. The year 1986 was selected as the initial year because it corresponds to the average age of the current cost dollars invested in the Company's property, plant and equipment measured by Mr. Kelly. As previously discussed, the year 1986 was also used as the starting point for measuring the productivity factor.

As described above, the Replacement Cost rate base receives 47.05% weight in the determination of the Company's fair value rate base for purposes of my analysis. The remaining weight (i.e., 52.95%) has been assigned to the Original Cost rate base. On this basis, therefore, it is necessary to employ these same weights in removing historical inflation from the cost of capital. That is to say, 1.44% (3.05% × .4705) should be removed from the Company's cost of equity in order to provide the same recognition for historical inflation that is reflected in the fair value rate base.

Based upon these considerations, I have reduced the Company's 11.75% cost of equity to 10.31% (11.75% - 1.44%) to reflect the same historical inflation and weight assigned to it in the fair value rate base calculation. As shown on Petitioner's Exhibit PRM-2, Schedule 13, the 10.31% equity rate and Mr. Goocher's capital structure (Petitioner's Exhibit RLG-2, page 1) provides a rate of return of 7.27% applicable to a fair value rate base. In this way, I have synchronized both the amount of historical inflation reflected in the rate base and the weight assigned to current value that was used to develop the fair value rate base. In my opinion, a rate of return of 7.27% on the Company's fair value rate base would be fair and reasonable.

Q. Does this conclude your prepared direct testimony?

A. Yes.

Petitioner's Exhibit No. PRM-1
Vectren South-Gas

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH-GAS)

Appendices A Through I to Accompany

the Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Concerning

Rate of Return

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service regulated firms. In this regard, I have supervised the preparation of rate of return studies which were employed in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty (30) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia; and the

Philadelphia Gas Commission. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000).

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

I am a member of the Society of Utility and Regulatory Financial Analysis (formerly the National Society of Rate of Return Analysts) and have attended several Financial Forums sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-Wythe School of Law, College of William and Mary. I also attended an Executive Seminar sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October 1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

Date	Occasion	Sponsor
April 2006	Thirty-eighth Financial Forum	Society of Utility & Regulatory Financial Analysts
April 2001	Thirty-third Financial Forum	Society of Utility & Regulatory Financial Analysts
December 2000	Pennsylvania Public Utility Law Conference: Non-traditional Players in the Water Industry	Pennsylvania Bar Institute
July 2000	EEI Member Workshop Developing Incentives Rates: Application and Problems	Edison Electric Institute
February 2000	The Sixth Annual FERC Briefing	Exnet and Bruder, Gentile & Marcoux, LLP
March 1994	Seventh Annual Proceeding	Electric Utility Business Environment Conf.
May 1993	Financial School	New England Gas Assoc.
April 1993	Twenty-Fifth Financial Forum	National Society of Rate of Return Analysts
June 1992	Rate and Charges Subcommittee Annual Conference	American Water Works Association
May 1992	Rates School	New England Gas Assoc.
October 1989	Seventeenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners Florida Public Service Commission and University of Utah

October 1988	Sixteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
May 1988	Twentieth Financial Forum	National Society of Rate of Return Analysts
October 1987	Fifteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
September 1987	Rate Committee Meeting	American Gas Association
May 1987	Pennsylvania Chapter annual meeting	National Association of Water Companies
October 1986	Eighteenth Financial Forum	National Society of Rate of Return
October 1984	Fifth National on Utility Ratemaking Fundamentals	American Bar Association
March 1984	Management Seminar	New York State Telephone Association
February 1983	The Cost of Capital Seminar	Temple University, School of Business Admin.
May 1982	A Seminar on Regulation and The Cost of Capital	New Mexico State University, Center for Business Research and Services
October 1979	Economics of Regulation	Brown University

EVALUATION OF RISK

The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk all else being equal. Because investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm is often defined as the uncertainty of achieving expected performance, and is sometimes viewed as a probability distribution of possible outcomes. Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a consequence, high risk firms must offer investors higher returns than low risk firms which pay less to attract capital from investors. This is because the level of uncertainty, or risk of not realizing expected returns, establishes the compensation required by investors in the capital markets. Of course, the risk of a firm must also be considered in the context of its ability to actually experience adequate earnings which conform with a fair rate of return. Thus, if there is a high probability that a firm will not perform well due to fundamentally poor market conditions, investors will demand a higher return.

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated firms than for non-regulated companies. For regulated public utilities, the cost of service formula gives the benefits of financial leverage to consumers in the form of lower revenue requirements. For non-regulated companies, all benefits of financial leverage are retained by the common stockholder. Although retaining none of the benefits, regulated firms bear the risk of financial leverage. Therefore, a regulated firm's rate of return on common equity must recognize the greater financial risk shown by the higher leverage typically employed by public utilities.

Although no single index or group of indices can precisely quantify the relative investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators, which are reflective of business risk, include the variability of the rate of return on equity, which is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and taxes other than income tax), which are indicative of profitability; the quality of earnings, which considers the degree to which earnings are the product of accounting principles or cost deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital in a company's capitalization is the measure of financial risk which is often analyzed in the context of the equity ratio (i.e., the complement of the debt ratio).

COST OF EQUITY--GENERAL APPROACH

Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation which lacks such a basis will inevitably fail to provide a utility with a fair rate of return except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods which have been employed to measure the cost of equity include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors. To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the payment of interest and principal to creditors has priority over the payment of dividends and return of capital to equity investors. Hence, equity investors require a higher rate of return than the yield on long-term corporate bonds.

The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk. Aside from the reliance on the risk-free rate of return, the CAPM gives specific quantification to systematic (or market) risk as measured by beta.

The Comparable Earnings approach measures the returns expected/experienced by other non-regulated firms and has been used extensively in rate of return analysis for over a half century. However, its popularity diminished in the 1970s and 1980s with the popularization of market-based models. Recently, there has been renewed interest in this approach. Indeed, the financial community has expressed the view that the regulatory process must consider the returns which are being achieved in the non-regulated sector so that public utilities can compete effectively in the capital markets. Indeed, with additional competition being introduced throughout the traditionally regulated public utility industry, returns expected to be realized by non-regulated firms have become increasing relevant in the ratesetting process. The Comparable Earnings approach considers directly those requirements and it fits the established standards for a fair rate of return set forth in the Bluefield decision. The Bluefield decisions requires that a fair return for a utility must be equal to that earned by firms of comparable risk.

DISCOUNTED CASH FLOW ANALYSIS

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if $100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be $46.32 (Value = $\$100\,.(1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present $46.32 price of an asset (where price = value), the $100 future expected cash flow to be received 10 years hence shows an 8% <u>annual</u> rate of return implicit in the price and future cash flows expected to be received.

In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate which reflects the risk or uncertainty associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If *P* represents price, *Kp* is the required rate of return on a preferred stock, and *D* is the annual dividend (*P* and *D* with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, *Kp*. In this circumstance:

$$P_0 = \frac{D_1}{(1+Kp)} + \frac{D_2}{(1+Kp)^2} + \frac{D_3}{(1+Kp)^3} + \mathrm{K} + \frac{D_n}{(1+Kp)^n}$$

If $D_1 = D_2 = D_3 = \ldots D_n$ as is the case for preferred stock, and *n* approaches infinity, as is the case for non-callable preferred stock without a sinking fund, then this equation reduces to:

$$P_0 = \frac{D_1}{Kp}$$

This equation can be used to solve for the annual rate of return on a preferred stock when the current price and subsequent annual dividends are known. For example, with D_1 = \$1.00, and P_0 = \$10, then Kp = \$1.00 ÷ \$10, or 10%.

The dividend discount equation, first shown, is the generic DCF valuation model for all equities, both preferred and common. While preferred stock generally pays a constant dividend, permitting the simplification subsequently noted, common stock dividends are not constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the generic form of the DCF. If, however, it is assumed that $D_1, D_2, D_3, \ldots D_n$ are systematically related to one another by a constant growth rate (g), so that $D_0 (1 + g) = D_1$, $D_1 (1 + g) = D_2$, $D_2 (1 + g) = D_3$ and so on approaching infinity, and if Ks (the required rate of return on a common stock) is greater than g, then the DCF equation can be reduced to:

$$P_0 = \frac{D_1}{Ks - g} \quad or \quad P_0 = \frac{D_0 (1+g)}{Ks - g}$$

which is the periodic form of the "Gordon" model.[1] Proof of the DCF equation is found in all modern basic finance textbooks. This DCF equation can be easily solved as:

$$Ks = \frac{D_0 (1+g)}{P_0} + g$$

which is the periodic form of the Gordon Model commonly applied in estimating equity rates of return in rate cases. When used for this purpose, Ks is the annual rate of return on common equity demanded by investors to induce them to hold a firm's common stock. Therefore, the variables D_0, P_0 and g must be estimated in the context of the market for equities, so that the rate of return, which a public utility is permitted the opportunity to earn, has meaning and reflects the investor-required cost rate.

[1] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

Application of the Gordon model with market derived variables is straightforward. For example, using the most recent prior annualized dividend *(D_0)* of $0.80, the current price *(P_0)* of $10.00, and the investor expected dividend growth rate *(g)* of 5%, the solution of the DCF formula provides a 13.4% rate of return. The dividend yield component in this instance is 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual rate of return required by investors. The capital gain component of the total return may be calculated with two adjacent future year prices. For example, in the eleventh year of the holding period, the price per share would be $17.10 as compared with the price per share of $16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

Some DCF devotees believe that it is more appropriate to estimate the required return on equity with a model which permits the use of multiple growth rates. This may be a plausible approach to DCF, where investors expect different dividend growth rates in the near term and long run. If two growth rates, one near term and one long-run, are to be used in the context of a price *(P_0)* of $10.00, a dividend *($D_0$)* of $0.80, a near-term growth rate of 5.5%, and a long-run expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

Use of DCF in Ratesetting

The DCF method can provide a misleading measure of the cost of equity in the ratesetting process when stock prices diverge from book values by a meaningful margin. When the difference between share values and book values is significant, the results from the DCF can result in a misspecified cost of equity when those results are applied to book value. This is because investor expected returns, as described by the DCF model, are related to the market value of common stock. This discrepancy is shown by the following example. If it is assumed, hypothetically, that investors require a 12.5% return on their common stock investment value (i.e., the market price per share) when share values represent 150% of book value, investors would require a total annual return of $1.50 per share on a $12.00 market value to realize their expectations. If, however, this 12.5% market-determined cost rate is applied to an original cost rate base which is equivalent to the book value of common stock of $8.00 per share, the utility's actual earnings per share would be only $1.00. This would result in a $.50 per share earnings shortfall which would deny the utility the ability to satisfy investor expectations.

As a consequence, a utility could not withstand these DCF results applied in a rate case and also sustain its financial integrity. This is because $1.00 of earnings per share and a 75% dividend payout ratio would provide earnings retention growth of just 3.125% (i.e., $1.00 x .75 = $0.75, and $1.00 - $0.75 = $0.25 ÷ $8.00 = 3.125%). In this example, the earnings retention growth rate plus the 6.25% dividend yield ($0.75 ÷ $12.00) would equal 9.375% (6.25% + 3.125%) as indicated by the DCF model. This DCF result is the same as the utility's rate of dividend payments on its book value (i.e., $0.75 ÷ $8.00 = 9.375%). This situation provides the utility with no earnings cushion for its dividend payment because the DCF result equals the dividend rate on book value (i.e., both rates are 9.375% in the example). Moreover, if the price employed in my example were higher than 150% of book value, a "negative" earnings cushion would develop and cause the need for a dividend reduction because the DCF result would be less than the dividend rate on book value. For these reasons, the usefulness of the DCF method significantly diminishes as market prices and book values diverge.

Further, there is no reason to expect that investors would necessarily value utility stocks equal to their book value. In fact, it is rare that utility stocks trade at book value. Moreover, high market-to-book ratios may be reflective of general market sentiment. Were regulators to use the results of a DCF model, that fails to produce the required return when applied to an original cost rate base, they would penalize a company with high market-to-book ratios. This clearly would penalize a regulated firm and its investors that purchased the stock at its current price. When investor expectations are not fulfilled, the market price per share will decline and a new, different equity cost rate would be indicated from the lower price per share. This condition suggests that the current price would be subject to disequilibrium and would not allow a reasonable calculation of the cost of equity. This situation would also create a serious disincentive for management initiative and efficiency. Within that framework, a perverse set of goals and rewards would result, i.e., a high authorized rate of return in a rate case would be the reward for poor financial performance, while low rates of return would be the reward for good financial performance. As such, the DCF results should not be used alone to determine the cost of equity, but should be used along with other complementary methods.

Dividend Yield

The historical annual dividend yield for the Gas Group is shown on Schedule 3. The 2001-2005 five-year average dividend yield was 4.5% for the Gas Group. The monthly dividend yields for the past twelve months are shown graphically on Schedule 5. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs two business days before the record date of the dividend (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). During a quarter (here defined as 91 days), the price of a stock moves up ratably by the dividend amount as the ex-dividend date approaches. The stock's price then falls by the amount of the dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the quarterly dividend since the time of the last ex-dividend date and to remove that amount from the price. This adjustment reflects normal recurring pricing of stocks in the market, and establishes a price which will reflect the true yield on a stock.

A six-month average dividend yield has been used to recognize the prospective orientation of the ratesetting process as explained in the direct testimony. For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized. An adjustment to the dividend yield component, when computed with annualized dividends, is required based upon investor expectation of quarterly dividend increases.

The procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, developed below. The DCF equation, showing the quarterly dividend payments as D_0, may be stated in this fashion:

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 2.625% (5.25% x .5) for the Gas Group, which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield would be

4.13% (4.02% x 1.02625) for the Gas Group.

Another DCF model that reflects the discrete growth in the quarterly dividend (D_0) is as follows:

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 4.15% (4.02% x 1.03260) for the Gas Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

In either of the preceding DCF dividend yield adjustments, there is no recognition for the compound returns attributed to the quarterly dividend payments. Investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments (D_0), results in a third DCF formulation:

$$k = \left[\left(1 + \frac{D_0}{P_0}\right)^4 - 1\right] + g$$

This DCF equation provides no further recognition of growth in the quarterly dividend. Combining discrete quarterly dividend growth with quarterly compounding would provide the following DCF formulation, stating the quarterly dividend payments (D_0):

$$k = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was

1.0050% (4.02% ÷ 4) for the Gas Group. The compound dividend yield would be 4.13% (1.010179^4-1) for the Gas Group, recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For the Gas Group, a 4.14% forward-looking dividend yield is the average (4.13% + 4.15% + 4.13% = 12.41% ÷ 3) of the adjusted dividend yield using the form $D_0/P_0\ (1+.5g)$, the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth.

Growth Rate

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. It would, however, require 100 years of future dividend payments so that the discounted value of those payments would equate to the present price so that the discount rate and the rate of return shown by the simplified Gordon form of the DCF model would be about the same. A century of dividend receipts represents an unrealistic investment horizon from almost any perspective. Because stocks are not held by investors forever, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, investor expected returns in the equity market are provided by capital appreciation of the investment as well as receipt of dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment holding period to arrive at the investor expected return.

In its constant growth form, the DCF assumes that with a constant return on book common equity and constant dividend payout ratio, a firm's earnings per share, dividends per share and book value per share will grow at the same constant rate, absent any external financing by a firm. Because these constant growth assumptions do not actually prevail in the capital markets, the capital appreciation potential of an equity investment is best measured by the expected growth in earnings per share. Since the traditional form of the DCF assumes no change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as earnings per share. Hence, the capital gains yield is best measured by earnings per share growth using company-specific variables.

Investors consider both historical and projected data in the context of the expected growth rate for a firm. An investor can compute historical growth rates using compound growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth rates as provided in widely-circulated, influential publications. However, a traditional constant growth DCF analysis that is limited to such inputs suffers from the assumption of no change in the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as earnings. Some of the factors which actually contribute to investors' expectations of earnings growth and which should be considered in assessing those expectations, are: (i) the earnings rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of additional common equity, (iv) reacquisition of common stock previously issued, (v) changes in financial leverage, (vi) acquisitions of new business opportunities, (vii) profitable liquidation of assets, and (viii) repositioning of existing assets. The realities of the equity market regarding total return expectations, however, also reflect factors other than these inputs. Therefore, the DCF model contains overly restrictive limitations when the growth component is stated in terms of earnings per share (the basis for the capital gains yield) or dividends per share (the basis for the infinite dividend discount model). In these situations, there is inadequate recognition of the capital gains yields arising from stock price growth which could exceed earnings or dividends growth.

To assess the growth component of the DCF, analysts' projections of future growth influence investor expectations as explained above. One influential publication is The Value Line Investment Survey which contains estimated future projections of growth. The Value Line Investment Survey provides growth estimates which are stated within a common economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical economic environment is represented by components and subcomponents of the National Income Accounts which reflect in the aggregate assumptions concerning the unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales, earnings and dividends of a company to appropriate components or subcomponents of the future National Income Accounts. These calculations provide a consistent basis for the published forecasts. Value Line's evaluation of a specific company's future prospects are considered in the context of specific operating characteristics that influence the published projections. Of particular importance for regulated firms, Value Line considers the regulatory quality, rates of return recently authorized, the historic ability of the firm to actually experience the authorized rates of return, the firm's budgeted capital spending, the firm's financing forecast, and the dividend payout ratio. The wide circulation of this source and frequent reference to Value Line in financial circles indicate that this publication has an influence on investor judgment with regard to expectations for the future.

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("IBES"). The IBES service provides data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts. The earnings estimates are obtained from financial analysts at brokerage research departments and from institutions whose securities analysts are projecting earnings for companies in the First Call universe of companies. Other services that tabulate earnings forecasts and publish them are Zacks Investment Research and Market Guide (which is provided over the Internet by Reuters). As with the IBES/First Call forecasts, Zacks and Reuters/Market Guide provide consensus forecasts collected from analysts for most publically traded companies.

In each of these publications, forecasts of earnings per share for the current and subsequent year receive prominent coverage. That is to say, IBES/First Call, Zacks, Reuters/Market Guide, and Value Line show estimates of current-year earnings and projections for the next year. While the DCF model typically focusses upon long-run estimates of growth, stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the near-term earnings per share growth rates should also be factored into a growth rate determination.

Although forecasts of future performance are investor influencing[2], equity investors may also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. It is apparent that any serious investor would advise himself/herself of historical performance prior to taking an

[2] As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

investment position in a firm. Earnings per share and dividends per share represent the principal financial variables which influence investor growth expectations.

Other financial variables are sometimes considered in rate case proceedings. For example, a company's internal growth rate, derived from the return rate on book common equity and the related retention ratio, is sometimes considered. This growth rate measure is represented by the Value Line forecast "*BxR*" shown on Schedule 7 Internal growth rates are often used as a proxy for book value growth. Unfortunately, this measure of growth is often not reflective of investor-expected growth. This is especially important when there is an indication of a prospective change in dividend payout ratio, earned return on book common equity, change in market-to-book ratios or other fundamental changes in the character of the business. Nevertheless, I have also shown the historical and projected growth rates in book value per share and internal growth rates.

Leverage Adjustment

As noted previously, the divergence of stock prices from book values creates a conflict within the DCF model when the results of a market-derived cost of equity are applied to the common equity account measured at book value in the ratesetting context. This is the situation today where the market price of stock exceeds its book value for most companies. This divergence of price and book value also creates a financial risk difference, whereby the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value. It is a well-accepted fact of financial theory that a relatively higher proportion of equity in the capitalization has less financial risk than another capital structure more heavily weighted with debt. This is the situation for the Gas Group where the market value of its capitalization contains more equity than is shown by the book capitalization. The following comparison demonstrates this situation where the market capitalization is developed by taking the "Fair Value of Financial Instruments" (Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting Standards ("FAS") No. 107) as shown in the annual report for these companies and the market value of the common equity using the price of stock. The comparison of capital structure ratios is:

Gas Group	Capitalization at Market Value (Fair Value)	Capitalization at Book Value (Carrying Amounts)
Long-term Debt	33.30%	46.53%
Preferred Stock	0.17	0.25
Common Equity	66.53	53.22
Total	100.00%	100.00%

With regard to the capital structure ratios represented by the carrying amounts shown above, there are some variances from the ratios shown on Schedule 3. These variances arise from the use of balance sheet values in computing the capital structure ratios shown on Schedule 3 and the use of the Carrying Amounts of the Financial Instruments according to FAS 107 (the Carrying Amounts were used in the table shown above to be comparable to the Fair Value amounts used in the comparison calculations).

With the capital ratios calculated above, is necessary to first calculate the cost of equity for a firm without any leverage. The cost of equity for an unleveraged firm using the capital structure ratios calculated with market values is:

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D / E) - (ku - d)\ P / E$$

$$8.55\% = 9.39\% - (((8.55\%-6.01\%)\ .65)\ 33.30\%/66.53\%) - (8.55\% - 6.21\%)\ 0.17\%/66.53\%$$

where *ku* = cost of equity for an all-equity firm, *ke* = market determined cost equity, *i* = cost of debt[3], *d* = dividend rate on preferred stock[4], *D* = debt ratio, *P* = preferred stock ratio, and *E* = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 8.55% using the market value of the Gas Group's capitalization. Having determined that the cost of equity is 8.55% for a firm with 100% equity, the rate of return on common equity associated with the book value capital structure is:

$$ke = ku + (((ku - i)\ 1\text{-}t)\ D / E) + (ku - d)\ P / E$$

$$10.00\% = 8.55\% + (((8.55\%-6.01\%).65)\ 46.53\%/53.22\%) + (8.55\%-6.21\%)\ 0.25\%/53.22\%$$

[3] The cost of debt is the six-month average yield on Moody's A rated public utility bonds.

[4] The cost of preferred is the six-month average yield on Moody's "a" rated preferred stock.

FLOTATION COST ADJUSTMENT

The rate of return on common equity must be high enough to avoid dilution when additional common equity is issued. In this regard, the rate of return on book common equity for public utilities requires recognition of specific factors other than just the market-determined cost of equity. A market price of common stock above book value is necessary to attract future capital on reasonable terms in competition with other seekers of equity capital. Non-regulated companies traditionally have experienced common stock prices consistently above book value. For a public utility to be competitive in the capital markets, similar recognition should be provided, given the understated value of net plant investment which is represented by historical costs much lower than current cost. Moreover, the market value of a public utility stock must be above book value to provide recognition of market pressure, issuance and selling expenses which reduce the net proceeds realized from the sale of new shares of common stock. A market price of stock above book value will maintain the financial integrity of shares previously issued and is necessary to avoid dilution when new shares are offered.

The rate of return on common equity should provide for the underwriting discount and company issuance expenses associated with the sale of new common stock. It is the net proceeds, after payment of these costs that are available to the company, because the issuance costs are paid from the initial offering price to the public. Market pressure occurs when the news of an impending issue of new common shares impacts the pre-offering price of stock. The stock price often declines because of the prospect of an increase in the supply of shares. The difficulty encountered in measuring market pressure relates to the time frame considered, general market conditions, and management action during the offering period. An indication of negative market pressure could be the product of the techniques employed to measure pressure and not the prospect of an additional supply of shares related to the new issue.

Even in the situation where a company will not issue common stock during the near term, the flotation cost adjustment factor should be applied to the common equity cost rate. A public utility must be in a competitive capital attraction posture at all times. To deny recognition of a market value of equity above book value would be discriminatory when other comparable companies receive an allowance in this regard. Moreover, to reduce the return rate on common equity by failing to recognize this factor would likewise result in a company being less competitive in the bond market, because a lower resulting overall rate of return would provide less competitive fixed-charge coverage. It cannot be said that a public utility's stock price already considers an allowance for flotation costs. This is because investors in either fixed-income bonds or common stocks seek their required rate of return by reference to alternative investment opportunities, and are not concerned with the issuance costs incurred by a firm borrowing long-term debt or issuing common equity.

Historical data concerning issuance and selling expenses (excluding market pressure) is shown on Schedule 8. To adjust for the cost of raising new common equity capital, the rate of return on common equity should recognize an appropriate multiple in order to allow for a market price of stock above book value. This would provide recognition for flotation costs, which are shown to be 3.9% for public offerings of common stocks by gas companies from 2001 to 2005. Because these costs are not recovered elsewhere, they must be recognized in the rate of return. Since I apply the flotation cost to the entire cost of equity, I have only used a modification factor of 1.02 which is applied to the unadjusted DCF-measure of the cost of equity to cover issuance expense. If the modification factor were applied to only a portion of the cost of equity, such as just the dividend yield, then a higher factor would be necessary.

INTEREST RATES

Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation, that is reflected in current interest rates, may be quite different than the prevailing rate of inflation.

Rates of interest also vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity risk. The Treasury has been issuing inflation-indexed notes which automatically provide compensation to investors for future inflation, thereby providing a lower current yield on these issues.

Interest Rate Environment

Federal Reserve Board ("Fed") policy actions which impact directly short-term interest rates also substantially affect investor sentiment in long-term fixed-income securities markets. In this regard, the Fed has often pursued policies designed to build investor confidence in the fixed-income securities market. Formative Fed policy has had a long history, as exemplified by the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the financial system which increased the level and volatility of interest rates. The Fed has indicated that it will follow a monetary policy designed to promote non-inflationary economic growth.

As background to the recent levels of interest rates, history shows that the Open Market Committee of the Federal Reserve board ("FOMC") began a series of moves toward lower short-term interest rates in mid-1990 -- at the outset of the previous recession. Monetary policy was influenced at that time by (i) steps taken to reduce the federal budget deficit, (ii) slowing economic growth, (iii) rising unemployment, and (iv) measures intended to avoid a credit crunch. Thereafter, the Federal government initiated several bold proposals to deal with future borrowings by the Treasury. With lower expected federal budget deficits and reduced Treasury borrowings, together with limitations on the supply of new 30-year Treasury bonds, long-term interest rates declined to a twenty-year low, reaching a trough of 5.78% in October 1993.

On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate (i.e., the interest rate on excess overnight bank reserves). The initial increase represented the first rise in short-term interest rates in five years. The series of seven increases doubled the Fed Funds rate to 6%. The increases in short-term interest rates also caused long-term rates to move up, continuing a trend which began in the fourth quarter of 1993. The cyclical peak in long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

Beginning in mid-February 1996, long-term interest rates moved upward from their previous lows. After initially reaching a level of 6.75% on March 15, 1996, long-term interest rates continued to climb and reached a peak of 7.19% on July 5 and 8, 1996. For the period leading up to the 1996 Presidential election, long-term Treasury bonds generally traded within this range. After the election, interest rates moderated, returning to a level somewhat below the previous trading range. Thereafter, in December 1996, interest rates returned to a range of 6.5% to 7.0% which existed for much of 1996.

On March 25, 1997, the FOMC decided to tighten monetary conditions through a one-quarter percentage point increase in the Fed Funds rate. This tightening increased the Fed Funds rate to 5.5%. In making this move, the FOMC stated that it was concerned by persistent strength of demand in the economy, which it feared would increase the risk of inflationary imbalances that could eventually interfere with the long economic expansion.

In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in response to an increase in demand for Treasury securities caused by a flight to safety triggered by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market makes these bonds an attractive investment in times of crisis. This is because Treasury securities encompass a very large market which provides ease of trading and carry a premium for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically important 6% level for the first time since 1993.

Through the first half of 1998, the yields on long-term Treasury bonds fluctuated within a range of about 5.6% to 6.1% reflecting their attractiveness and safety. In the third quarter of 1998, there was further deterioration of investor confidence in global financial markets. This loss of confidence followed the moratorium (i.e., default) by Russia on its sovereign debt and fears associated with problems in Latin America. While not significant to the global economy in the aggregate, the August 17 default by Russia had a significant negative impact on investor confidence, following earlier discontent surrounding the crisis in Asia. These events subsequently led to a general pull back of risk-taking as displayed by banks growing reluctance to lend, worries of an expanding credit crunch, lower stock prices, and higher yields on bonds of riskier companies. These events contributed to the failure of the hedge fund, Long-Term Capital Management.

In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-term Congressional elections. The FOMC's action was based upon concerns over how increasing weakness in foreign economies would affect the U.S. economy. As recently as July 1998, the FOMC had been more concerned about fighting inflation than the state of the economy. The initial rate cut was the first of three reductions by the FOMC. Thereafter, the yield on long-term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-term Treasury yields below 5% had not been seen since 1967. Unlike the first rate cut that was widely anticipated, the second rate reduction by the FOMC was a surprise to the markets. A third reduction in short-term interest rates occurred in November 1998 when the FOMC reduced the Fed Funds rate to 4.75%.

All of these events prompted an increase in the prices for Treasury bonds which lead to the low yields described above. Another factor that contributed to the decline in yields on long-term Treasury bonds was a reduction in the supply of new Treasury issues coming to market due to the Federal budget surplus -- the first in nearly 30 years. The dollar amount of Treasury bonds being issued declined by 30% in two years thus resulting in higher prices and lower yields. In addition, rumors of some struggling hedge funds unwinding their positions further added to the gains in Treasury bond prices.

The financial crisis that spread from Asia to Russia and to Latin America pushed nervous investors from stocks into Treasury bonds, thus increasing demand for bonds, just when supply was shrinking. There was also a move from corporate bonds to Treasury bonds to take advantage of appreciation in the Treasury market. This resulted in a certain amount of exuberance for Treasury bond investments that formerly was reserved for the stock market. Moreover, yields in the fourth quarter of 1998 became extremely volatile as shown by Treasury yields that fell from 5.10% on September 29 to 4.70 percent on October 5, and thereafter returned to 5.10% on October 13. A decline and rebound of 40 basis points in Treasury yields in a two-week time frame is remarkable.

Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%. This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points higher than the level that occurred at the height of the Asian currency and stock market crisis. At the time, these actions were taken in response to more normally functioning financial markets, tight labor markets, and a reversal of the monetary ease that was required earlier in response to the global financial market turmoil.

As the year 2000 drew to a close, economic activity slowed and consumer confidence began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds rate to 5.50%. The FOMC described its actions as "a rapid and forceful response of monetary policy" to eroding consumer and business confidence exemplified by weaker retail sales and business spending on capital equipment and cut backs in manufacturing production. Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August 21, 2001, the FOMC lowered the Fed Funds in steps consisting of three 50 basis points decrements followed by two 25 basis points decrements. These actions took the Fed Funds rate to 3.50%. The FOMC observed on August 21, 2001:

> "Household demand has been sustained, but business profits and capital spending continue to weaken and growth abroad is slowing, weighing on the U.S. economy. The associated easing of pressures on labor and product markets is expected to keep

> inflation contained.
>
> Although long-term prospects for productivity growth and the economy remain favorable, the Committee continues to believe that against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are weighted mainly toward conditions that may generate economic weakness in the foreseeable future."

After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis points reductions in the Fed Funds rate. The first reduction occurred on September 17, 2001 and followed the four-day closure of the financial markets following the terrorist attacks. The second reduction occurred at the October 2 meeting of the FOMC where it observed:

> "The terrorist attacks have significantly heightened uncertainty in an economy that was already weak. Business and household spending as a consequence are being further damped. Nonetheless, the long-term prospects for productivity growth and the economy remain favorable and should become evident once the unusual forces restraining demand abate."

Afterward, the FOMC reduced the Fed Funds rate by 50 basis points on November 6, 2001 and by 25 basis points on December 11, 2001. In total, short-term interest rates were reduced by the FOMC eleven (11) times during the year 2001. These actions cut the Fed Funds rate by 4.75% and resulted in 1.75% for the Fed Funds rate.

In an attempt to deal with weakening fundamentals in the economy recovering from the recession that began in March 2001, the FOMC provided a psychologically important one-half percentage point reduction in the federal funds rate. The rate cut was twice as large as the market expected, and brought the fed funds rate to 1.25% on November 6, 2002. The FOMC stated that:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still-robust underlying growth in productivity, is providing important ongoing support to economic activity. However, incoming economic data have tended to confirm that greater uncertainty, in part attributable to heightened geopolitical risks, is currently inhibiting spending, production, and employment. Inflation and inflation expectations remain well contained.
>
> In these circumstances, the Committee believes that today's additional monetary easing should prove helpful as the economy

> works its way through this current soft spot. With this action, the Committee believes that, against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are balanced with respect to the prospects for both goals in the foreseeable future."

As 2003 unfolded, there was a continuing expectation of lower yields on Treasury securities. In fact, the yield on ten-year Treasury notes reached a 45-year low near the end of the second quarter of 2003. For long-term Treasury bonds, those yields culminated with a 4.24% yield on June 13, 2003. Soon thereafter, the FOMC reduced the Fed Funds rate by 25 basis points on June 25, 2003. In announcing its action, the FOMC stated:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still robust underlying growth in productivity, is providing important ongoing support to economic activity. Recent signs point to a firming in spending, markedly improved financial conditions, and labor and product markets that are stabilizing. The economy, nonetheless, has yet to exhibit sustainable growth. With inflationary expectations subdued, the Committee judged that a slightly more expansive monetary policy would add further support for an economy which it expects to improve over time."

Thereafter, intermediate and long-term Treasury yields moved marketedly higher. Higher yields on long-term Treasury bonds, which exceeded 5.00% can be traced to: (i) the market's disappointment that the Fed Funds rate was not reduced below 1.00%, (ii) an indication that the Fed will not use unconventional methods for implementing monetary policy, (iii) growing confidence in a strengthening economy, and (iv) a Federal budget deficit that is projected to be $455 billion in 2003 (reported, subsequently, the actually deficit was $374 billion) and $475 billion in 2004 (revised subsequently, the estimated deficit is $500 billion in 2004). All these factors significantly changed the seniment in the bond market.

For the remainder of 2003, the FOMC continued with its balanced monetary policy, thereby retaining the 1% Fed Funds rate. However, in 2004, the FOMC initiated a policy of moving toward a more neutral Fed Funds rate (i.e., removing the bias of abnormal low rates). On June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, June 30, 2005, August 9, 2005, September 20, 2005, November 1, 2005, December 13, 2005, January 31, 2006, March 28, 2006, May 10, 2006, and June 29, 2006, the FOMC increased the Fed Funds rate in seventeen

25 basis point increments. These policy actions are widely interpreted as part of the process of moving toward a more neutral range for the Fed Funds rate. In its June 29, 2006 press release, the FOMC stated:

> "Recent indicators suggest that economic growth is moderating from its quite strong pace earlier this year, partly reflecting a gradual cooling of the housing market and the lagged effects of increases in interest rates and energy prices.
>
> Readings on core inflation have been elevated in recent months. Ongoing productivity gains have held down the rise in unit labor costs, and inflation expectations remain contained. However, the high levels of resource utilization and of the prices of energy and other commodities have the potential to sustain inflation pressures.
>
> Although the moderation in the growth of aggregate demand should help to limit inflation pressures over time, the Committee judges that some inflation risks remain. The extent and timing of any additional firming that may be needed to address these risks will depend on the evolution of the outlook for both inflation and economic growth, as implied by incoming information. In any event, the Committee will respond to changes in economic prospects as needed to support the attainment of its objectives."

Public Utility Bond Yields

The Risk Premium analysis of the cost of equity is represented by the combination of a firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the additional risk associated with the equity of a firm as explained in Appendix G. Due to the senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the prior claim which lenders have on the earnings and assets of a corporation.

As a generalization, all interest rates track to varying degrees of the benchmark yields established by the market for Treasury securities. Public utility bond yields usually reflect the underlying Treasury yield associated with a given maturity plus a spread to reflect the specific credit quality of the issuing public utility. Market sentiment can also have an influence on the spreads as described below. The spread in the yields on public utility bonds and Treasury bonds varies with market conditions, as does the relative level of interest rates at varying maturities shown by the yield curve.

Pages 1 and 2 of Schedule 9 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of Aaa, Aa, A, and Baa are known as "investment grades" and are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Schedule 9. There, it is shown that those spreads were about the one percentage during for the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As shown on page 3 of Schedule 9, the spread in yields between A-rated public utility bonds and 20-year Treasury bonds were about one percentage point prior to 1998, 1.32% in 1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.62% in 2003, 1.12% in 2004, and 1.01% in 2005. As shown by the monthly data presented on pages 4 and 5 of Schedule 9, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 1.05 percentage points for the twelve-months ended May 2006. For the six- and three-month periods ending May 2006, the yield spread was 1.08% and 1.07%, respectively.

Risk-Free Rate of Return in the CAPM

Regarding the risk-free rate of return (see Appendix H), pages 2 and 3 of Schedule 11 provide the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

> The Cost of Capital in a Regulatory Environment. When discounting cash flows projected over a long period, it is necessary to discount them by a long-term cost of capital. Additionally, regulatory processes for setting rates often specify or suggest that the desired rate of return for a regulated firm is that which would allow the firm to attract and retain debt and equity capital over the long term. Thus, the long-term cost of capital is typically the appropriate cost of capital to use in regulated ratesetting. (Stocks, Bonds, Bills and Inflation - 1992 Yearbook, pages 118-119)

As indicated above, long-term Treasury bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be avoided for several reasons. First, rates should be set on the basis of financial conditions that will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy, political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds.

RISK PREMIUM ANALYSIS

The cost of equity requires recognition of the risk premium required by common equities over long-term corporate bond yields. In the case of senior capital, a company contracts for the use of long-term debt capital at a stated coupon rate for a specific period of time and in the case of preferred stock capital at a stated dividend rate, usually with provision for redemption through sinking fund requirements. In the case of senior capital, the cost rate is known with a high degree of certainty because the payment for use of this capital is a contractual obligation, and the future schedule of payments is known. In essence, the investor-expected cost of senior capital is equal to the realized return over the entire term of the issue, absent default.

The cost of equity, on the other hand, is not fixed, but rather varies with investor perception of the risk associated with the common stock. Because no precise measurement exists as to the cost of equity, informed judgment must be exercised through a study of various market factors which motivate investors to purchase common stock. In the case of common equity, the realized return rate may vary significantly from the expected cost rate due to the uncertainty associated with earnings on common equity. This uncertainty highlights the added risk of a common equity investment.

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. As noted in Appendix F, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a lender. The cost of equity stated in terms of the familiar risk premium approach is:

$$k=i+RP$$

where, the cost of equity *("k")* is equal to the interest rate on long-term corporate debt *("i")*, plus an equity risk premium *("RP")* which represents the additional compensation for the riskier common equity.

Equity Risk Premium

The equity risk premium is determined as the difference in the rate of return on debt capital and the rate of return on common equity. Because the common equity holder has only a residual claim on earnings and assets, there is no assurance that achieved returns on common equities will equal expected returns. This is quite different from returns on bonds, where the investor realizes the expected return during the entire holding period, absent default. It is for this reason that common equities are always more risky than senior debt securities. There are investment strategies available to bond portfolio managers that immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas no such redemption is mandated for public utility common equities.

It is well recognized that the expected return on more risky investments will exceed the required yield on less risky investments. Neither the possibility of default on a bond nor the maturity risk detracts from the risk analysis, because the common equity risk rate differential (i.e., the investor-required risk premium) is always greater than the return components on a bond. It should also be noted that the investment horizon is typically long-run for both corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or starting point with which to track and measure the cost rate of common equity capital. There is no need to segment the bond yield according to its components, because it is the total return demanded by investors that is important for determining the risk rate differential for common equity. This is because the complete bond yield provides the basis to determine the differential, and as such, consistency requires that the computed differential must be applied to the complete bond yield when applying the risk premium approach. To apply the risk rate differential to a partial bond yield would result in a misspecification of the cost of equity because the computed differential was initially determined by reference to the entire bond return.

The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (here defined as one year) computed over long time spans. This analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved. Accordingly, historical holding period returns must not be analyzed over an unduly short period because near-term realized results may not have fulfilled investors' expectations. Moreover, specific past period results may not be representative of investment fundamentals expected for the future. This is especially apparent when the holding period returns include negative returns which are not representative of either investor requirements of the past or investor expectations for the future. The short-run phenomenon of unexpected returns (either positive or negative) demonstrates that an unduly short historical period would not adequately support a risk premium analysis. It is important to distinguish between investors' motivation to invest, which encompass positive return expectations, and the knowledge that losses can occur. No rational investor would forego payment for the use of capital, or expect loss of principal, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Schedule 10 provides the historical holding period returns for the S&P Public Utility Index which has been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in Stocks, Bonds, Bills and Inflation published by Ibbotson & Associates. The tabulation begins with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public Utility Index. I have considered all reliable data for this study to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

The risk rate differentials for all equities, as measured by the S&P Composite, are established by reference to long-term corporate bonds. For public utilities, the risk rate differentials are computed with the S&P Public Utilities as compared with public utility bonds.

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of the central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be appropriate. The median returns are also appropriate in ratesetting because they are a measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return which divides the entire series of annual returns in half and are representative of a return that symbolizes, in a meaningful way, the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix H, the long-term cost of capital in rate cases requires the use of the arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2005, the risk premiums for each class of equity are:

	S&P Composite	S&P Public Utilities
Arithmetic Mean	5.78%	5.27%
Geometric Mean	4.14%	3.18%
Median	8.94%	6.95%
Midpoint of Range	6.54%	5.07%
Average	6.16%	5.17%

The empirical evidence suggests that the common equity risk premium is higher for the S&P Composite Index compared to the S&P Public Utilities.

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations, the results provided on page 2 of Schedule 10 should also be considered. One of these sub-periods included the 54-year period, 1952-2005. These years follow the historic 1951 Treasury-Federal Reserve Accord which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 2005 and 1979 through 2005 contain events subsequent to the initial oil shock and the advent of monetarism as

Fed policy, respectively. For the 54-year, 32-year and 27-year periods, the public utility risk premiums were 6.05%, 5.19%, and 5.20% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Schedule 10.

CAPITAL ASSET PRICING MODEL

Modern portfolio theory provides a theoretical explanation of expected returns on portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium which is proportional to the non-diversifiable (or systematic) risk of a security.

The CAPM theory has several unique assumptions that are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted that found that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Because it is not known whether the average investor holds a well-diversified portfolio, the CAPM must also be used with other models of the cost of equity.

To apply the traditional CAPM theory, three inputs are required: the beta coefficient *("β")*, a risk-free rate of return *("Rf")*, and a market premium *("Rm - Rf")*. The cost of equity stated in terms of the CAPM is:

$$k = Rf + \beta\,(Rm - Rf)$$

As previously indicated, it is important to recognize that the academic research has shown that the security market line was flatter than that predicted by the CAPM theory and it had a higher intercept than the risk-free rate. These tests indicated that for portfolios with betas less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for portfolios with betas above 1.0, these companies had lower returns than indicated by the traditional CAPM theory. Once again, CAPM assumes that through portfolio diversification investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Therefore, the CAPM must also be used with other models of the cost of equity, especially when it is not known whether the average public utility investor holds a well-diversified portfolio.

Beta

The beta coefficient is a statistical measure which attempts to identify the non-diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of return on a particular security with general market movements. Under the CAPM theory, a security that has a beta of 1.0 should theoretically provide a rate of return equal to the return rate provided by the market. When employing stock price changes in the derivation of beta, a stock with a beta of 1.0 should exhibit a movement in price which would track the movements in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one percent increase in the return on the market will result, on average, in a one percent increase in the return on the particular investment. An investment which has a beta less than 1.0 is considered to be less risky than the market.

The beta coefficient ("β"), the one input in the CAPM application which specifically applies to an individual firm, is derived from a statistical application which regresses the returns on an individual security (dependent variable) with the returns on the market as a whole (independent variable). The beta coefficients for utility companies typically describe a small proportion of the total investment risk because the coefficients of determination (R^2) are low.

Page 1 of Schedule 11 provides the betas published by Value Line. By way of explanation, the Value Line beta coefficient is derived from a "straight regression" based upon the percentage change in the weekly price of common stock and the percentage change weekly of the New York Stock Exchange Composite average using a five-year period. The raw historical beta is adjusted by Value Line for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the computation of its betas.

Market Premium

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return *("Rm - Rf")*. In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is established with forecasts by Value Line using estimated dividend yields and capital appreciation potential.

With regard to the forecast data, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to the May 5, 2006, edition of The Value Line Investment Survey Summary and Index, (see page 5 of Schedule 11) the total return on the universe of Value Line equities is:

	Dividend Yield	+	Median Appreciation Potential	=	Median Total Return
As of May 5, 2006	1.6%	+	8.78%[1]	=	10.38%

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by Value Line. Another measure of the total market return is provided by the DCF return on the S&P 500 Composite index. As shown below, that return is 12.70%.

DCF Result for the S&P 500 Composite

D/P	(	1+.5g	)	+	g	=	k
1.86%	(	1.05370	)	+	10.74%	=	12.70%

where:	Price (P)	at	31-May-2006	=	1270.09
	Dividend (D)	for	1st Qtr '06	=	5.91
	Dividend (D)		annualized	=	23.64
	Growth (g)		First Call EpS	=	10.74%

Using these indicators, the total market return is 11.54% (10.38% + 12.70% = 23.08% ÷ 2) using both the Value Line and S&P derived returns. With the 11.54% forecast market return and the 5.50% risk-free rate of return, a 6.04% (11.54% - 5.50%) market premium would be

[1] The estimated median appreciation potential is forecast to be 40% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 8.78% (i.e., $1.40^{.25} - 1$).

indicated using forecast market data.

With regard to the historical data, I provided the rates of return from long-term historical time periods that have been widely circulated among the investment and academic community over the past several years, as shown on page 6 of Schedule 11. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the data provided on page 6 of Schedule 11, I calculate a market premium using the common stock arithmetic mean returns of 12.3% less government bond arithmetic mean returns of 5.8%. For the period 1926-2005, the market premium was 6.5% (12.3% - 5.8%). I should note that the arithmetic mean must be used in the CAPM because it is a single period model. It is further confirmed by Ibbotson who has indicated:

> *Arithmetic Versus Geometric Differences*
> For use as the expected equity risk premium in the CAPM, the *arithmetic* or *simple difference* of the *arithmetic* means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.
>
> *Arithmetic Versus Geometric Means*
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values. This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154)

For the CAPM, a market premium of 6.27% (6.5% + 6.04% = 12.54% ÷ 2) would be reasonable which is the average of the 6.5% using historical data and a market premium of 6.04% using forecasts.

COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follow:

Timeliness Rank

> The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

Safety Rank

> A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating an ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH-GAS)

IURC CAUSE NO.

FINANCIAL EXHIBIT

TO ACCOMPANY THE

DIRECT TESTIMONY

OF

PAUL R. MOUL

Southern Indiana Gas and Electric Company
D/B/A Vectren Energy Delivery Of Indiana, Inc.
(Vectren South-Gas)

Index of Schedules

Southern Indiana Gas and Electric Compnay
Rate of Return Applicable to an Original Cost Rate Base
For the Test Year Ending March 31, 2006

Investor Provided Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.10%	6.04%	2.72%
Common Equity	54.90%	11.75%	6.45%
Total	100.00%		9.17%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its overall cost of capital:

Pre-tax coverage of interest expense based upon a 40.525% composite federal and state income tax rate (13.56% ÷ 2.72%)	4.99 x
Post-tax coverage of interest expense (9.17% ÷ 2.72%)	3.37 x

For Ratesetting Purposes	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	38.65%	6.04%	2.33%
Common Equity	47.05%	11.75%	5.53%
Customer Deposits	0.48%	5.39%	0.03%
Cost-free Capital	13.06%	0.00%	0.00%
JDITC	0.76%	9.17%	0.07%
Total	100.00%		7.96%

Southern Indiana Gas & Electric Company
Capitalization and Financial Statistics
2001-2005, Inclusive

	2005	2004	2003	2002	2001	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 900.1	$ 768.8	$ 770.2	$ 752.2	$ 675.4	
Short-Term Debt	$ 93.3	$ 170.5	$ 83.8	$ 39.4	$ 81.5	
Total Capital	$ 993.5	$ 939.3	$ 853.9	$ 791.7	$ 757.0	
						Average
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	41.6%	48.7%	48.7%	50.3%	50.5%	48.0%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
Common Equity (1)	58.4%	51.3%	51.3%	49.6%	49.4%	52.0%
	100.0%	100.0%	100.0%	99.9%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	47.1%	58.0%	53.7%	52.8%	55.8%	53.5%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
Common Equity (1)	52.9%	42.0%	46.3%	47.2%	44.1%	46.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity (1)	11.3%	12.3%	12.7%	16.8%	11.8%	13.0%
Operating Ratio (2)	79.6%	78.7%	77.4%	84.4%	84.1%	80.8%
Coverage incl. AFUDC (3)						
Pre-tax: All Interest Charges	4.14 x	4.18 x	4.21 x	4.84 x	3.92 x	4.26 x
Post-tax: All Interest Charges	2.86 x	2.92 x	2.97 x	3.56 x	2.93 x	3.05 x
Overall Coverage: All Int. & Pfd. Div.	2.86 x	2.92 x	2.97 x	3.56 x	2.82 x	3.03 x
Coverage excl. AFUDC (3)						
Pre-tax: All Interest Charges	4.08 x	4.07 x	4.01 x	4.68 x	3.77 x	4.12 x
Post-tax: All Interest Charges	2.80 x	2.81 x	2.78 x	3.40 x	2.78 x	2.91 x
Overall Coverage: All Int. & Pfd. Div.	2.80 x	2.80 x	2.77 x	3.40 x	2.69 x	2.89 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	3.0%	5.8%	9.8%	6.2%	7.6%	6.5%
Effective Income Tax Rate	40.9%	39.7%	38.6%	33.3%	33.9%	37.3%
Internal Cash Generation/Construction (4)	71.4%	54.5%	29.4%	66.4%	46.3%	53.6%
Gross Cash Flow/ Avg. Total Debt (5)	25.7%	24.9%	20.8%	24.9%	19.9%	23.2%
Gross Cash Flow Interest Coverage (6)	5.63 x	5.90 x	4.66 x	5.41 x	4.51 x	5.22 x
Common Dividend Coverage (7)	2.87 x	2.52 x	1.75 x	2.32 x	1.91 x	2.27 x

See Page 2 for Notes.

Southern Indiana Gas and Electric Company d/b/a Vectren South-Gas
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally generated funds from operations after payment of all cash dividends.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow plus interest charges divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Utility COMPUSTAT

Gas Group
Capitalization and Financial Statistics [1]
2001-2005, Inclusive

	2005	2004	2003	2002	2001	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 1,690.1	$ 1,434.8	$ 1,155.1	$ 1,066.3	$ 1,040.3	
Short-Term Debt	$ 173.1	$ 133.1	$ 218.6	$ 141.2	$ 141.8	
Total Capital	$ 1,863.2	$ 1,567.9	$ 1,373.7	$ 1,207.5	$ 1,182.1	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	16 x	16 x	14 x	17 x	15 x	16 x
Market/Book Ratio	195.9%	186.4%	179.4%	167.2%	176.4%	181.1%
Dividend Yield	3.8%	4.1%	4.6%	5.1%	4.9%	4.5%
Dividend Payout Ratio	61.2%	63.2%	63.0%	86.3%	70.4%	68.8%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	46.6%	46.6%	47.2%	50.9%	51.5%	48.5%
Preferred Stock	0.4%	0.4%	0.3%	0.4%	0.8%	0.5%
Common Equity [2]	53.0%	53.0%	52.6%	48.7%	47.7%	51.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	52.2%	51.7%	56.2%	56.7%	57.4%	54.8%
Preferred Stock	0.4%	0.4%	0.3%	0.4%	0.7%	0.4%
Common Equity [2]	47.4%	47.9%	43.5%	42.9%	41.9%	44.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	12.0%	12.0%	12.9%	10.6%	12.3%	12.0%
Operating Ratio [3]	89.8%	88.8%	87.4%	85.8%	88.6%	88.1%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	4.25 x	4.40 x	4.26 x	3.33 x	3.35 x	3.92 x
Post-tax: All Interest Charges	3.01 x	3.10 x	3.01 x	2.43 x	2.47 x	2.80 x
Overall Coverage: All Int. & Pfd. Div.	3.00 x	3.09 x	2.99 x	2.41 x	2.41 x	2.78 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	4.24 x	4.38 x	4.24 x	3.31 x	3.32 x	3.90 x
Post-tax: All Interest Charges	3.00 x	3.09 x	2.99 x	2.42 x	2.43 x	2.79 x
Overall Coverage: All Int. & Pfd. Div.	2.99 x	3.07 x	2.98 x	2.39 x	2.37 x	2.76 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.8%	1.0%	1.0%	1.1%	2.4%	1.3%
Effective Income Tax Rate	37.6%	37.6%	37.7%	38.3%	37.3%	37.7%
Internal Cash Generation/Construction [5]	82.1%	95.1%	117.8%	79.6%	79.0%	90.7%
Gross Cash Flow/ Avg. Total Debt [6]	19.6%	21.2%	21.7%	17.6%	17.9%	19.6%
Gross Cash Flow Interest Coverage [7]	4.37 x	5.07 x	5.13 x	3.95 x	3.63 x	4.43 x
Common Dividend Coverage [8]	2.97 x	3.43 x	3.62 x	3.04 x	2.81 x	3.17 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Gas Group includes companies that (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey, (iv) ______________________________,
(v) have not cut or omitted their dividend since 2000, (vi) are not currently the target of a merger or acquisition, and (vii) have at least 70% of their assets represented by regulated operations.

Ticker	Company	Corporate Credit Ratings Moody's	S&P	Stock Traded	S&P Stock Ranking	Value Line Beta
ATG	AGL Resources, Inc.	A3	A-	NYSE	A-	0.90
ATO	Atmos Energy Corp.	Baa3	BBB	NYSE	B+	0.70
LG	Laclede Group, Inc.	Baa1	A	NYSE	B+	0.80
NJR	New Jersey Resources Corp	Aa3	A+	NYSE	A	0.80
NWN	Northwest Natural Gas	A3	AA-	NYSE	B+	0.70
PNY	Piedmont Natural Gas Co.	A3	A	NYSE	A-	0.75
SJI	South Jersey Industries, Inc.	Baa2	BBB+	NYSE	B+	0.65
WGL	WGL Holdings, Inc.	A2	AA-	NYSE	B+	0.80
	Average	A3	A		B+	0.76

Note: Ratings are those of utility subsidiaries

Source of Information: Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation
S&P Stock Guide

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2001-2005, Inclusive

	2005	2004	2003	2002	2001	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 14,644.5	$ 14,562.2	$14,658.8	$ 14,236.2	$13,783.4	
Short-Term Debt	$ 485.3	$ 278.7	$ 276.6	$ 952.3	$ 1,204.1	
Total Capital	$ 15,129.8	$ 14,840.9	$14,935.4	$ 15,188.5	$14,987.5	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	18 x	15 x	13 x	15 x	17 x	16 x
Market/Book Ratio	195.5%	180.1%	149.0%	151.3%	183.6%	171.9%
Dividend Yield	3.7%	3.8%	4.2%	5.0%	4.1%	4.2%
Dividend Payout Ratio	58.9%	73.3%	59.9%	75.3%	64.1%	66.3%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	56.6%	58.3%	59.8%	60.4%	58.9%	58.8%
Preferred Stock	1.2%	1.5%	1.6%	1.8%	2.3%	1.7%
Common Equity [2]	42.2%	40.2%	38.6%	37.8%	38.9%	39.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	58.5%	59.7%	61.3%	63.5%	62.9%	61.2%
Preferred Stock	1.2%	1.5%	1.6%	1.6%	2.1%	1.6%
Common Equity [2]	40.3%	38.8%	37.2%	34.9%	35.0%	37.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.9%	11.1%	9.8%	7.7%	14.5%	10.8%
Operating Ratio [3]	83.0%	84.5%	84.9%	84.5%	85.9%	84.6%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.01 x	2.88 x	2.51 x	2.36 x	2.84 x	2.72 x
Post-tax: All Interest Charges	2.41 x	2.32 x	2.07 x	1.95 x	2.22 x	2.19 x
Overall Coverage: All Int. & Pfd. Div.	2.37 x	2.28 x	2.03 x	1.90 x	2.17 x	2.15 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.97 x	2.85 x	2.47 x	2.31 x	2.80 x	2.68 x
Post-tax: All Interest Charges	2.37 x	2.29 x	2.03 x	1.90 x	2.18 x	2.15 x
Overall Coverage: All Int. & Pfd. Div.	2.34 x	2.25 x	1.99 x	1.86 x	2.13 x	2.11 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.9%	3.1%	1.7%	2.6%	2.0%	2.1%
Effective Income Tax Rate	31.6%	26.3%	40.9%	29.4%	28.1%	31.3%
Internal Cash Generation/Construction [5]	110.4%	127.2%	128.0%	90.6%	88.6%	109.0%
Gross Cash Flow/ Avg. Total Debt [6]	19.7%	19.7%	20.3%	18.2%	17.7%	19.1%
Gross Cash Flow Interest Coverage [7]	4.20 x	4.21 x	4.34 x	3.98 x	3.57 x	4.06 x
Common Dividend Coverage [8]	4.12 x	4.83 x	5.20 x	4.07 x	3.83 x	4.41 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities (1)

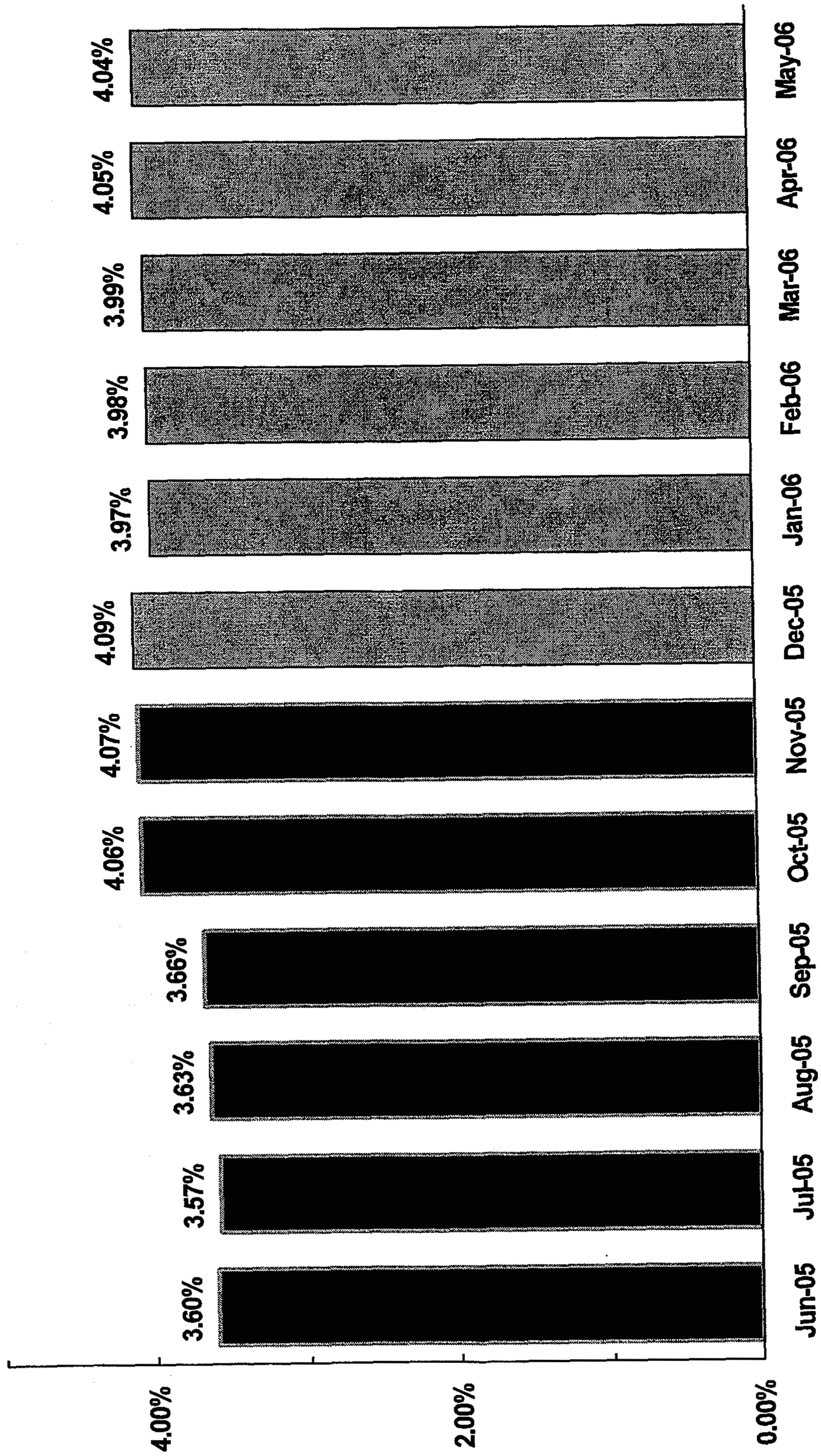
	Ticker	Credit Rating (2) Moody's	S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
Allegheny Energy	AYE	Baa3	BB+	NYSE	B-	1.85
Ameren Corporation	AEE	A2	BBB+	NYSE	A-	0.75
American Electric Power	AEP	Baa2	BBB	NYSE	B	1.20
CMS Energy	CMS	Ba1	BB	NYSE	C	1.45
CenterPoint Energy	CNP	Baa3	BBB	NYSE	B	0.65
Consolidated Edison	ED	A1	A	NYSE	B+	0.65
Constellation Energy Group	CEG	A3	BBB+	NYSE	B	0.95
DTE Energy Co.	DTE	Baa1	BBB	NYSE	B+	0.70
Dominion Resources	D	Baa1	BBB	NYSE	B+	0.95
Duke Energy	DUK	Baa2	BBB	NYSE	B+	1.20
Edison Int'l	EIX	Baa1	BBB+	NYSE	B	1.05
Entergy Corp.	ETR	Baa2	BBB	NYSE	B+	0.85
Exelon Corp.	EXC	A3	BBB+	NYSE	B+	0.80
FPL Group	FPL	A1	A	NYSE	A-	0.80
FirstEnergy Corp.	FE	Baa2	BBB	NYSE	B+	0.75
Keyspan Energy	KSE	A3	A	NYSE	B	0.85
NICOR Inc.	GAS	A1	AA	NYSE	B	1.15
NiSource Inc.	NI	Baa2	BBB	NYSE	B	0.80
PG&E Corp.	PCG	Baa1	BBB	NYSE	B	1.10
PPL Corp.	PPL	Baa1	A-	NYSE	B	1.00
Peoples Energy	PGL	A1	A-	NYSE	B	0.85
Pinnacle West Capital	PNW	Baa2	BBB-	NYSE	A-	0.90
Progress Energy, Inc.	PGN	Baa1	BBB	NYSE	B+	0.80
Public Serv. Enterprise Inc.	PEG	Baa1	BBB	NYSE	B+	0.90
Sempra Energy	SRE	A2	A	NYSE	B	1.00
Southern Co.	SO	A2	A	NYSE	A-	0.65
TECO Energy	TE	Baa2	BBB-	NYSE	B-	1.00
TXU CORP	TXU	Baa3	BBB-	NYSE	B	1.05
Xcel Energy Inc	XEL	A3	BBB+	NYSE	B	0.80
Average for S&P Utilities		Baa1	BBB+		B	0.95

Note: (1) Includes companies contained in S&P Utility Compustat. AES Corp. and Dynegy, Inc. are not included.
(2) Ratings are those of utility subsidiaries

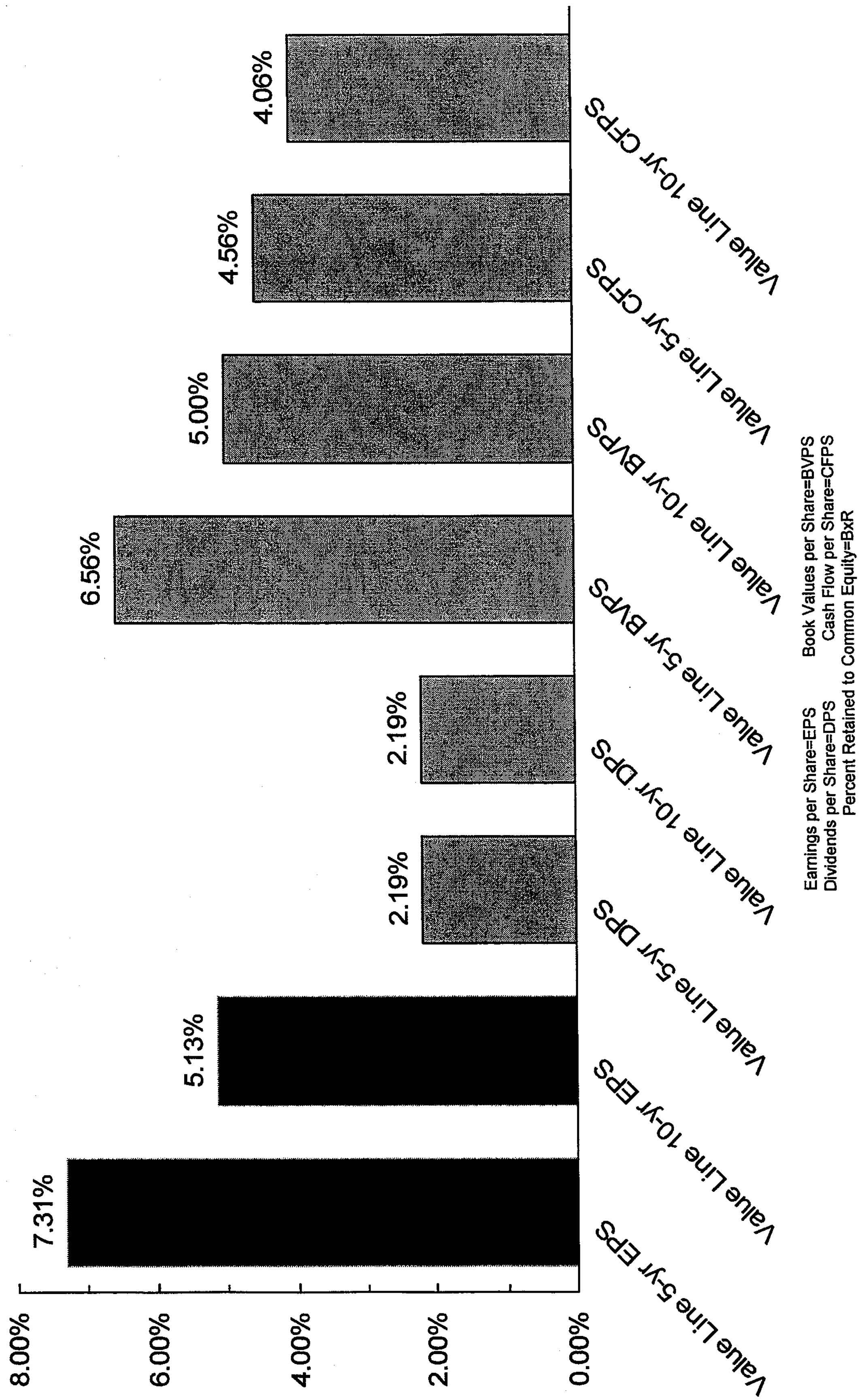
Source of Information: Moody's Investors Service
Standard & Poor's Corporation
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

Gas Group

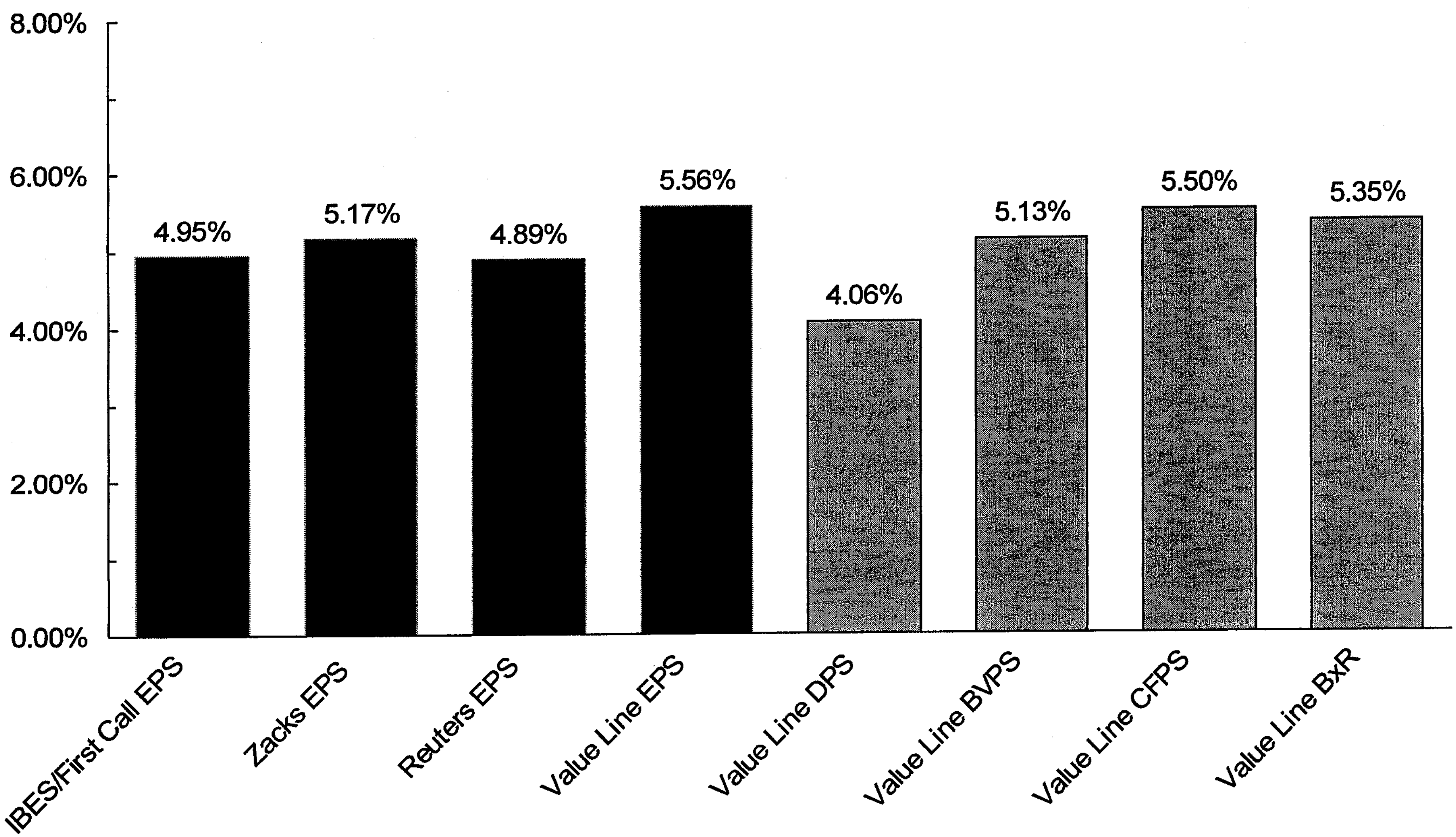
Monthly Dividend Yields



Gas Group
Historical Growth Rates



Gas Group
Five-Year Projected Growth Rates



Earnings per Share=EPS   Book Values per Share=BVPS
Dividends per Share=DPS   Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

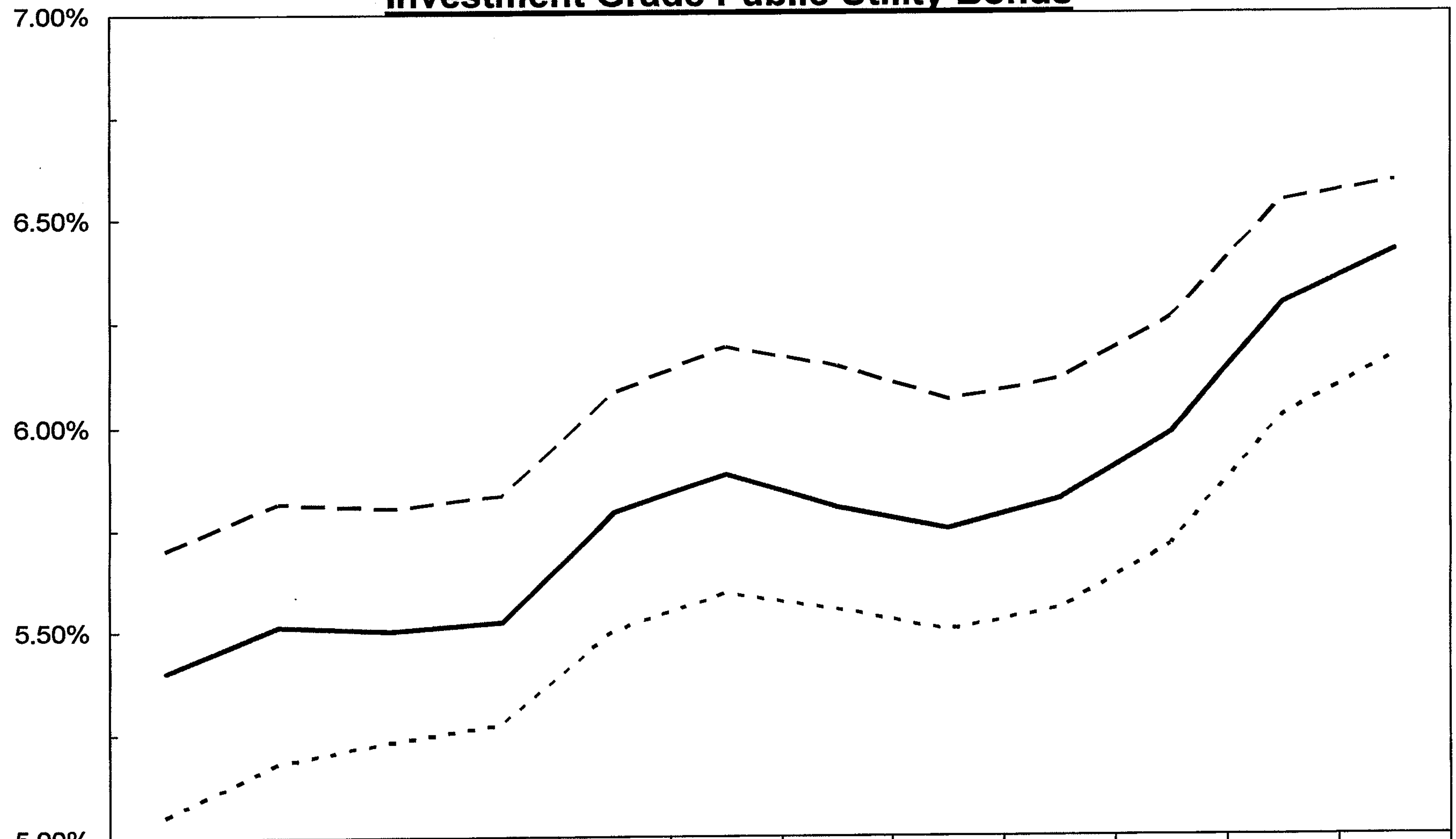
Natural Gas Industry
Analysis of Public Offerings of Common Stock
Years 2001-2005

	WGL Holdings	UTILICORP	MDU Resources	AGL RESOURCES	SOUTHERN UNION CO.	ATMOS ENERGY	VECTREN CORP.	SEMPRA ENERGY	PIEDMONT NATURAL
Date of Offering	6/26/2001	1/25/2002	11/29/2002	2/11/2003	6/5/2003	6/18/2003	8/7/2003	10/8/2003	1/20/2004
No. of shares offered (000)	1,790	11,000	2,100	5,600	9,500	4,000	6,500	15,000	4,250
Dollar amt. of offering ($000)	$ 47,847	$ 253,000	$ 50,400	$ 123,200	$ 152,000	$ 101,240	$ 148,265	$ 420,000	$ 180,625
Price to public	$ 26.730	$ 23.000	$ 24.200	$ 22.000	$ 16.000	$ 25.310	$ 22.810	$ 28.000	$ 42.500
Underwriter's discounts and commission	$ 0.895	$ 0.748	$ 0.720	$ 0.770	$ 0.560	$ 1.013	$ 0.798	$ 0.840	$ 1.490
Gross Proceeds	$ 25.835	$ 22.252	$ 23.480	$ 21.230	$ 15.440	$ 24.297	$ 22.012	$ 27.160	$ 41.010
Estimated company issuance expenses	$ 0.031	NA	$ 0.092	$ 0.045	$ 0.089	$ 0.095	$ 0.046	$ 0.033	NA
Net proceeds to company per share	$ 25.804	$ 22.252	$ 23.388	$ 21.185	$ 15.351	$ 24.202	$ 21.966	$ 27.127	$ 41.010
Underwriter's discount as a percent of offering price	3.3%	3.3%	3.0%	3.5%	3.5%	4.0%	3.5%	3.0%	3.5%
Issuance expense as a percent of offering price	0.1%	NA	0.4%	0.2%	0.6%	0.4%	0.2%	0.1%	NA
Total Issuance and selling expense as as a percent of offering price	3.4%	3.3%	3.4%	3.7%	4.1%	4.4%	3.7%	3.1%	3.5%

	UGI CORP.	NORTHWEST NATURAL	LACLEDE GROUP	SOUTHERN UNION CO.	AQUILA	ATMOS ENERGY	AGL RESOURCES	SOUTHERN UNION CO.	SEMCO Energy	Average
Date of Offering	3/18/2004	3/30/2004	5/6/2004	7/26/2004	8/18/2004	10/21/2004	11/19/2004	2/7/2005	8/9/2005	
No. of shares offered (000)	7,500	1,200	1,500	11,000	40,000	14,000	9,600	14,913	4,300	
Dollar amt. of offering ($000)	$ 240,750	$ 37,200	$ 40,200	$ 206,250	$ 102,000	$ 346,500	$ 297,696	$ 342,999	$ 27,176	
Price to public	$ 32.100	$ 31.000	$ 26.800	$ 18.750	$ 2.550	$ 24.750	$ 31.010	$ 23.000	$ 6.320	
Underwriter's discounts and commission	$ 1.404	$ 1.010	$ 0.871	$ 0.656	$ 0.099	$ 0.990	$ 0.930	$ 0.700	$ 0.253	
Gross Proceeds	$ 30.696	$ 29.990	$ 25.929	$ 18.094	$ 2.451	$ 23.760	$ 30.080	$ 22.300	$ 6.067	
Estimated company issuance expenses	$ 0.020	$ 0.146	$ 0.067	$ 0.091	NA	NA	$ 0.042	$ 0.067	$ 0.070	
Net proceeds to company per share	$ 30.676	$ 29.844	$ 25.862	$ 18.003	$ 2.451	$ 23.760	$ 30.038	$ 22.233	$ 5.997	
Underwriter's discount as a percent of offering price	4.4%	3.3%	3.3%	3.5%	3.9%	4.0%	3.0%	3.0%	4.0%	3.5%
Issuance expense as a percent of offering price	0.1%	0.5%	0.3%	0.5%	NA	NA	0.1%	0.3%	1.1%	0.4%
Total Issuance and selling expense as as a percent of offering price	4.5%	3.8%	3.6%	4.0%	3.9%	4.0%	3.1%	3.3%	5.1%	3.9%

Source of Information: Public Utility Financial Tracker

Interest Rates for Investment Grade Public Utility Bonds



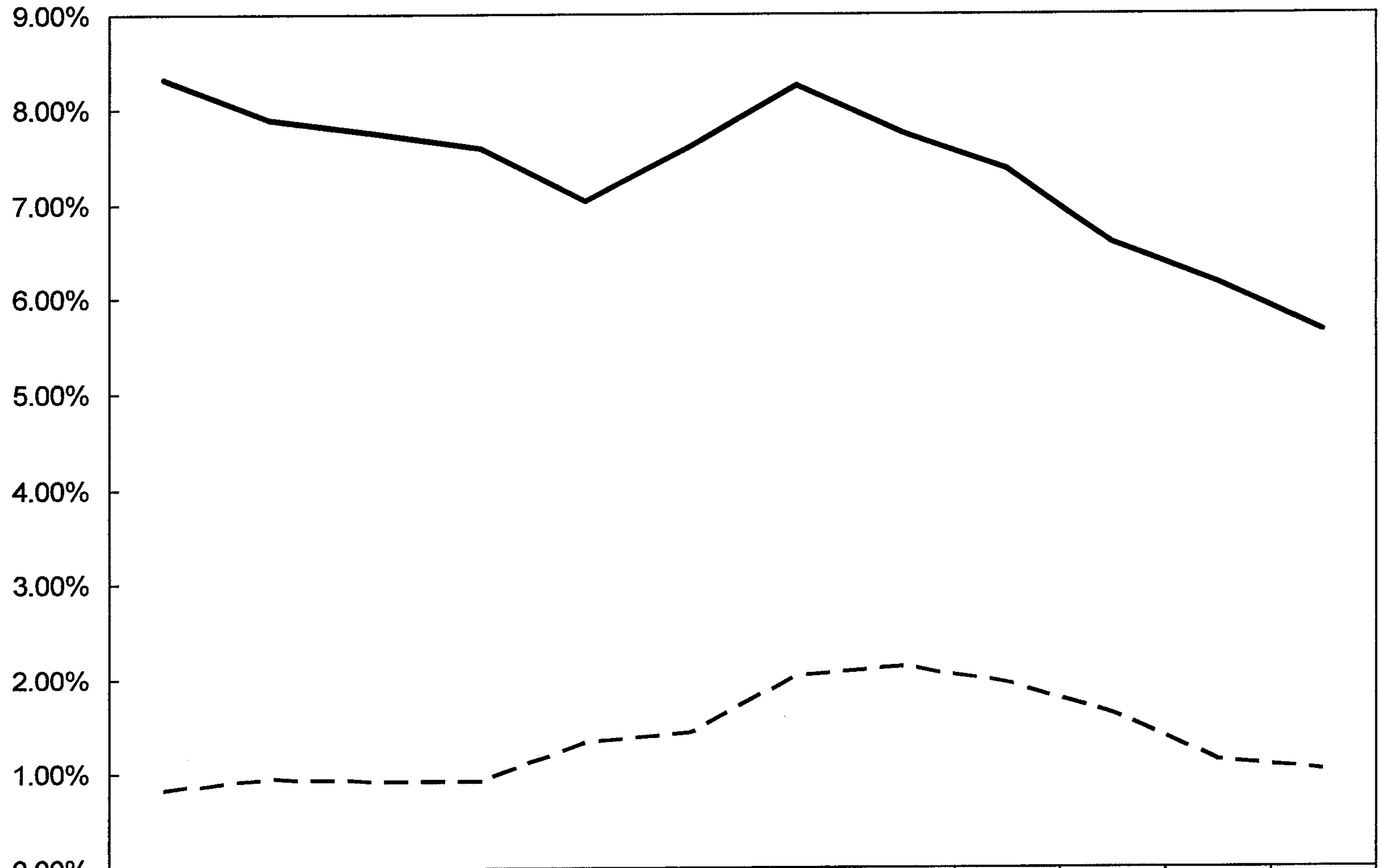
	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06
Aa	5.05%	5.18%	5.23%	5.27%	5.50%	5.59%	5.55%	5.50%	5.55%	5.71%	6.02%	6.16%
A	5.40%	5.51%	5.50%	5.52%	5.79%	5.88%	5.80%	5.75%	5.82%	5.98%	6.29%	6.42%
Baa	5.70%	5.81%	5.80%	5.83%	6.08%	6.19%	6.14%	6.06%	6.11%	6.26%	6.54%	6.59%

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2001-2005
and the Twelve Months Ended May 2006

Years	Aa Rated	A Rated	Baa Rated	Average
2001	7.58%	7.76%	8.03%	7.72%
2002	7.19%	7.37%	8.02%	7.53%
2003	6.40%	6.58%	6.84%	6.61%
2004	6.04%	6.16%	6.40%	6.20%
2005	5.44%	5.65%	5.93%	5.67%
Five-Year Average	6.53%	6.70%	7.04%	6.75%
Months				
Jun-05	5.05%	5.40%	5.70%	5.39%
Jul-05	5.18%	5.51%	5.81%	5.50%
Aug-05	5.23%	5.50%	5.80%	5.51%
Sep-05	5.27%	5.52%	5.83%	5.54%
Oct-05	5.50%	5.79%	6.08%	5.79%
Nov-05	5.59%	5.88%	6.19%	5.88%
Dec-05	5.55%	5.80%	6.14%	5.83%
Jan-06	5.50%	5.75%	6.06%	5.77%
Feb-06	5.55%	5.82%	6.11%	5.83%
Mar-06	5.71%	5.98%	6.26%	5.98%
Apr-06	6.02%	6.29%	6.54%	6.28%
May-06	6.16%	6.42%	6.59%	6.39%
Twelve-Month Average	5.53%	5.81%	6.09%	5.81%
Six-Month Average	5.75%	6.01%	6.28%	6.01%
Three-Month Average	5.96%	6.23%	6.46%	6.22%

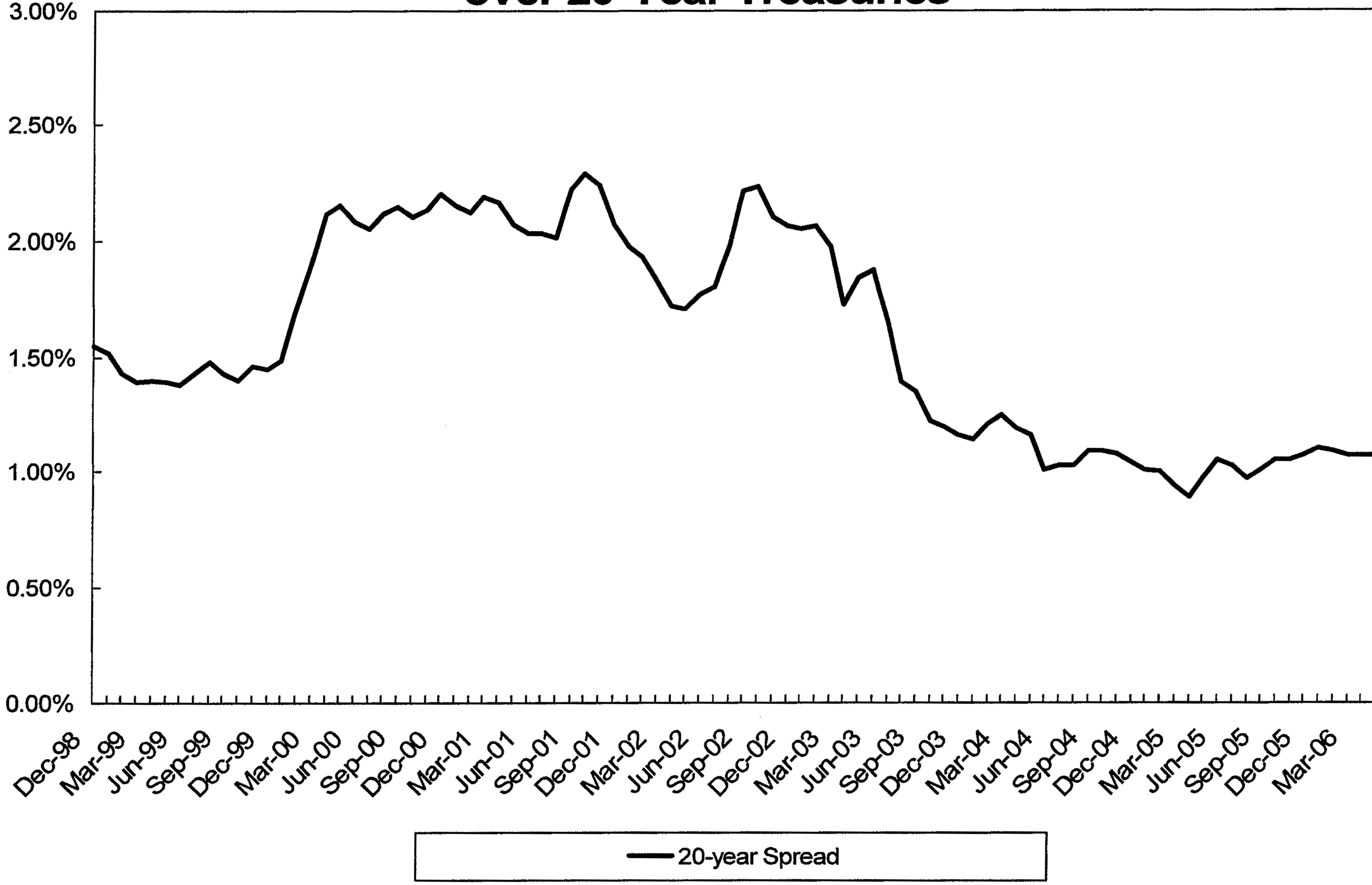
Source: Mergent Bond Record

Yields on A-rated Public Utility Bonds and Spreads over 20-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
A-rated Public Utility	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%	5.65%
Spread vs. 20-year	0.82%	0.94%	0.92%	0.91%	1.32%	1.42%	2.01%	2.13%	1.94%	1.62%	1.12%	1.01%

Interest Rate Spreads
A-rated Public Utility Bonds
over 20-Year Treasuries



Petitioner's Exhibit No. PRM-2
Vectren South-Gas
Page 18 of 30
Schedule 9 [4 of 5]

A rated Public Utility Bonds
over 20-Year Treasuries

Year	A-rated Public Utility	20-Year Treasuries Yield	Spread
Dec-98	6.91%	5.36%	1.55%
Jan-99	6.97%	5.45%	1.52%
Feb-99	7.09%	5.66%	1.43%
Mar-99	7.26%	5.87%	1.39%
Apr-99	7.22%	5.82%	1.40%
May-99	7.47%	6.08%	1.39%
Jun-99	7.74%	6.36%	1.38%
Jul-99	7.71%	6.28%	1.43%
Aug-99	7.91%	6.43%	1.48%
Sep-99	7.93%	6.50%	1.43%
Oct-99	8.06%	6.66%	1.40%
Nov-99	7.94%	6.48%	1.46%
Dec-99	8.14%	6.69%	1.45%
Jan-00	8.35%	6.86%	1.49%
Feb-00	8.25%	6.54%	1.71%
Mar-00	8.28%	6.38%	1.90%
Apr-00	8.29%	6.18%	2.11%
May-00	8.70%	6.55%	2.15%
Jun-00	8.36%	6.28%	2.08%
Jul-00	8.25%	6.20%	2.05%
Aug-00	8.13%	6.02%	2.11%
Sep-00	8.23%	6.09%	2.14%
Oct-00	8.14%	6.04%	2.10%
Nov-00	8.11%	5.98%	2.13%
Dec-00	7.84%	5.64%	2.20%
Jan-01	7.80%	5.65%	2.15%
Feb-01	7.74%	5.62%	2.12%
Mar-01	7.68%	5.49%	2.19%
Apr-01	7.94%	5.78%	2.16%
May-01	7.99%	5.92%	2.07%
Jun-01	7.85%	5.82%	2.03%
Jul-01	7.78%	5.75%	2.03%
Aug-01	7.59%	5.58%	2.01%
Sep-01	7.75%	5.53%	2.22%
Oct-01	7.63%	5.34%	2.29%
Nov-01	7.57%	5.33%	2.24%
Dec-01	7.83%	5.76%	2.07%
Jan-02	7.66%	5.69%	1.97%
Feb-02	7.54%	5.61%	1.93%
Mar-02	7.76%	5.93%	1.83%
Apr-02	7.57%	5.85%	1.72%
May-02	7.52%	5.81%	1.71%
Jun-02	7.42%	5.65%	1.77%
Jul-02	7.31%	5.51%	1.80%
Aug-02	7.17%	5.19%	1.98%
Sep-02	7.08%	4.87%	2.21%
Oct-02	7.23%	5.00%	2.23%
Nov-02	7.14%	5.04%	2.10%
Dec-02	7.07%	5.01%	2.06%
Jan-03	7.07%	5.02%	2.05%
Feb-03	6.93%	4.87%	2.06%
Mar-03	6.79%	4.82%	1.97%
Apr-03	6.64%	4.91%	1.73%
May-03	6.36%	4.52%	1.84%
Jun-03	6.21%	4.34%	1.87%
Jul-03	6.57%	4.92%	1.65%
Aug-03	6.78%	5.39%	1.39%
Sep-03	6.56%	5.21%	1.35%
Oct-03	6.43%	5.21%	1.22%
Nov-03	6.37%	5.17%	1.20%
Dec-03	6.27%	5.11%	1.16%
Jan-04	6.15%	5.01%	1.14%
Feb-04	6.15%	4.94%	1.21%
Mar-04	5.97%	4.72%	1.25%
Apr-04	6.35%	5.16%	1.19%
May-04	6.62%	5.46%	1.16%
Jun-04	6.46%	5.45%	1.01%
Jul-04	6.27%	5.24%	1.03%
Aug-04	6.14%	5.07%	1.07%
Sep-04	5.98%	4.89%	1.09%
Oct-04	5.94%	4.85%	1.09%
Nov-04	5.97%	4.89%	1.08%
Dec-04	5.92%	4.88%	1.04%
Jan-05	5.78%	4.77%	1.01%
Feb-05	5.61%	4.61%	1.00%
Mar-05	5.83%	4.89%	0.94%
Apr-05	5.64%	4.75%	0.89%
May-05	5.53%	4.56%	0.97%
Jun-05	5.40%	4.35%	1.05%
Jul-05	5.51%	4.48%	1.03%
Aug-05	5.50%	4.53%	0.97%
Sep-05	5.52%	4.51%	1.01%
Oct-05	5.79%	4.74%	1.05%
Nov-05	5.88%	4.83%	1.05%
Dec-05	5.80%	4.73%	1.07%
Jan-06	5.75%	4.65%	1.10%
Feb-06	5.82%	4.73%	1.09%
Mar-06	5.98%	4.91%	1.07%
Apr-06	6.29%	5.22%	1.07%
May-06	6.42%	5.35%	1.07%

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-2005

Year	S & P Composite Index	S & P Public Utility Index	Long Term Corporate Bonds	Public Utility Bonds
1928	43.61%	57.47%	2.84%	3.08%
1929	-8.42%	11.02%	3.27%	2.34%
1930	-24.90%	-21.96%	7.98%	4.74%
1931	-43.34%	-35.90%	-1.85%	-11.11%
1932	-8.19%	-0.54%	10.82%	7.25%
1933	53.99%	-21.87%	10.38%	-3.82%
1934	-1.44%	-20.41%	13.84%	22.61%
1935	47.67%	76.63%	9.61%	16.03%
1936	33.92%	20.69%	6.74%	8.30%
1937	-35.03%	-37.04%	2.75%	-4.05%
1938	31.12%	22.45%	6.13%	8.11%
1939	-0.41%	11.26%	3.97%	6.76%
1940	-9.78%	-17.15%	3.39%	4.45%
1941	-11.59%	-31.57%	2.73%	2.15%
1942	20.34%	15.39%	2.60%	3.81%
1943	25.90%	46.07%	2.83%	7.04%
1944	19.75%	18.03%	4.73%	3.29%
1945	36.44%	53.33%	4.08%	5.92%
1946	-8.07%	1.26%	1.72%	2.98%
1947	5.71%	-13.16%	-2.34%	-2.19%
1948	5.50%	4.01%	4.14%	2.65%
1949	18.79%	31.39%	3.31%	7.16%
1950	31.71%	3.25%	2.12%	2.01%
1951	24.02%	18.63%	-2.69%	-2.77%
1952	18.37%	19.25%	3.52%	2.99%
1953	-0.99%	7.85%	3.41%	2.08%
1954	52.62%	24.72%	5.39%	7.57%
1955	31.56%	11.26%	0.48%	0.12%
1956	6.56%	5.06%	-6.81%	-6.25%
1957	-10.78%	6.36%	8.71%	3.58%
1958	43.36%	40.70%	-2.22%	0.18%
1959	11.96%	7.49%	-0.97%	-2.29%
1960	0.47%	20.26%	9.07%	9.01%
1961	26.89%	29.33%	4.82%	4.65%
1962	-8.73%	-2.44%	7.95%	6.55%
1963	22.80%	12.36%	2.19%	3.44%
1964	16.48%	15.91%	4.77%	4.94%
1965	12.45%	4.67%	-0.46%	0.50%
1966	-10.06%	-4.48%	0.20%	-3.45%
1967	23.98%	-0.63%	-4.95%	-3.63%
1968	11.06%	10.32%	2.57%	1.87%
1969	-8.50%	-15.42%	-8.09%	-6.66%
1970	4.01%	16.56%	18.37%	15.90%
1971	14.31%	2.41%	11.01%	11.59%
1972	18.98%	8.15%	7.26%	7.19%
1973	-14.66%	-18.07%	1.14%	2.42%
1974	-26.47%	-21.55%	-3.06%	-5.28%
1975	37.20%	44.49%	14.64%	15.50%
1976	23.84%	31.81%	18.65%	19.04%
1977	-7.18%	8.64%	1.71%	5.22%
1978	6.56%	-3.71%	-0.07%	-0.98%
1979	18.44%	13.58%	-4.18%	-2.75%
1980	32.42%	15.08%	-2.76%	-0.23%
1981	-4.91%	11.74%	-1.24%	4.27%
1982	21.41%	26.52%	42.56%	33.52%
1983	22.51%	20.01%	6.26%	10.33%
1984	6.27%	26.04%	16.86%	14.82%
1985	32.16%	33.05%	30.09%	26.48%
1986	18.47%	28.53%	19.85%	18.16%
1987	5.23%	-2.92%	-0.27%	3.02%
1988	16.81%	18.27%	10.70%	10.19%
1989	31.49%	47.80%	16.23%	15.61%
1990	-3.17%	-2.57%	6.78%	8.13%
1991	30.55%	14.61%	19.89%	19.25%
1992	7.67%	8.10%	9.39%	8.65%
1993	9.99%	14.41%	13.19%	10.59%
1994	1.31%	-7.94%	-5.76%	-4.72%
1995	37.43%	42.15%	27.20%	22.81%
1996	23.07%	3.14%	1.40%	3.04%
1997	33.36%	24.69%	12.95%	11.39%
1998	28.58%	14.82%	10.76%	9.44%
1999	21.04%	-8.85%	-7.45%	-1.69%
2000	-9.11%	59.70%	12.87%	9.45%
2001	-11.88%	-30.41%	10.65%	5.85%
2002	-22.10%	-30.04%	16.33%	1.63%
2003	28.70%	26.11%	5.27%	10.01%
2004	10.87%	24.22%	8.72%	6.03%
2005	4.91%	16.79%	5.87%	3.02%
Geometric Mean	10.03%	8.65%	5.89%	5.47%
Arithmetic Mean	11.99%	11.02%	6.21%	5.75%
Standard Deviation	20.26%	22.67%	8.61%	7.93%
Median	13.38%	11.50%	4.44%	4.55%

Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-2005, 1952-2005, 1974-2005, and 1979-2005

Total Returns	Range: Geometric Mean	Range: Median	Midpoint	Point Estimate: Arithmetic Mean	Average of the Midpoint of Range and Point Estimate
1928-2005					
S&P Public Utility Index	8.65%	11.50%		11.02%	
Public Utility Bonds	5.47%	4.55%		5.75%	
Risk Differential	3.18%	6.95%	5.07%	5.27%	5.17%
1952-2005					
S&P Public Utility Index	10.82%	12.97%		12.37%	
Public Utility Bonds	6.21%	5.08%		6.52%	
Risk Differential	4.61%	7.89%	6.25%	5.85%	6.05%
1974-2005					
S&P Public Utility Index	12.54%	14.95%		14.57%	
Public Utility Bonds	8.70%	9.05%		9.06%	
Risk Differential	3.84%	5.90%	4.87%	5.51%	5.19%
1979-2005					
S&P Public Utility Index	13.15%	15.08%		15.06%	
Public Utility Bonds	9.15%	9.44%		9.49%	
Risk Differential	4.00%	5.64%	4.82%	5.57%	5.20%

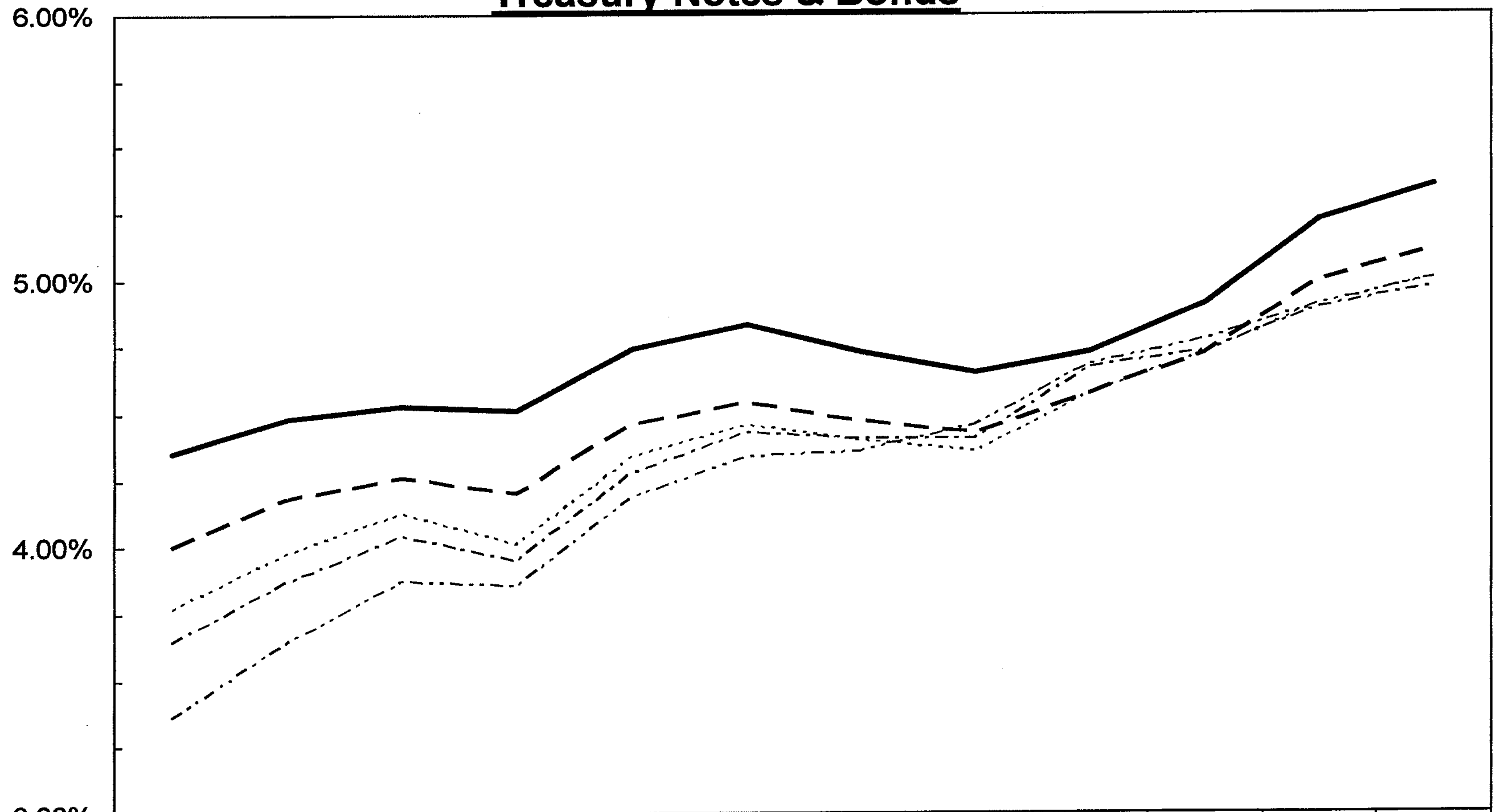
Value Line Betas

Gas Group

AGL Resources, Inc.	0.90
Atmos Energy Corp.	0.70
Laclede Group, Inc.	0.80
New Jersey Resources Corp.	0.80
Northwest Natural Gas	0.70
Piedmont Natural Gas Co.	0.75
South Jersey Industries, Inc.	0.65
WGL Holdings, Inc.	0.80
Average	0.76

Source of Information:
Value Line Investment Survey
March 17, 2006

Yields on Treasury Notes & Bonds



	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06
1-Year	3.36%	3.64%	3.87%	3.85%	4.18%	4.33%	4.35%	4.45%	4.68%	4.77%	4.90%	5.00%
2-Year	3.64%	3.87%	4.04%	3.95%	4.27%	4.42%	4.40%	4.40%	4.67%	4.73%	4.89%	4.97%
5-Year	3.77%	3.98%	4.12%	4.01%	4.33%	4.45%	4.39%	4.35%	4.57%	4.72%	4.90%	5.00%
10-Year	4.00%	4.18%	4.26%	4.20%	4.46%	4.54%	4.47%	4.42%	4.57%	4.72%	4.99%	5.11%
20-Year	4.35%	4.48%	4.53%	4.51%	4.74%	4.83%	4.73%	4.65%	4.73%	4.91%	5.22%	5.35%

Yields for Treasury Constant Maturities
Yearly for 2001-2005
and the Twelve Months Ended May 2006

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year
2001	3.49%	3.83%	4.09%	4.56%	4.88%	5.02%	5.63%
2002	2.00%	2.64%	3.10%	3.82%	4.30%	4.61%	5.43%
2003	1.24%	1.65%	2.10%	2.97%	3.52%	4.02%	4.96%
2004	1.89%	2.38%	2.78%	3.43%	3.87%	4.27%	5.04%
2005	3.62%	3.85%	3.93%	4.05%	4.15%	4.29%	4.64%
Five-Year Average	2.45%	2.87%	3.20%	3.77%	4.14%	4.44%	5.14%
Months							
Jun-05	3.36%	3.64%	3.69%	3.77%	3.86%	4.00%	4.35%
Jul-05	3.64%	3.87%	3.91%	3.98%	4.06%	4.18%	4.48%
Aug-05	3.87%	4.04%	4.08%	4.12%	4.18%	4.26%	4.53%
Sep-05	3.85%	3.95%	3.96%	4.01%	4.08%	4.20%	4.51%
Oct-05	4.18%	4.27%	4.29%	4.33%	4.38%	4.46%	4.74%
Nov-05	4.33%	4.42%	4.43%	4.45%	4.48%	4.54%	4.83%
Dec-05	4.35%	4.40%	4.39%	4.39%	4.41%	4.47%	4.73%
Jan-06	4.45%	4.40%	4.35%	4.35%	4.37%	4.42%	4.65%
Feb-06	4.68%	4.67%	4.64%	4.57%	4.56%	4.57%	4.73%
Mar-06	4.77%	4.73%	4.74%	4.72%	4.71%	4.72%	4.91%
Apr-06	4.90%	4.89%	4.89%	4.90%	4.94%	4.99%	5.22%
May-06	5.00%	4.97%	4.97%	5.00%	5.03%	5.11%	5.35%
Twelve-Month Average	4.28%	4.35%	4.36%	4.38%	4.42%	4.49%	4.75%
Six-Month Average	4.69%	4.68%	4.66%	4.66%	4.67%	4.71%	4.93%
Three-Month Average	4.89%	4.86%	4.87%	4.87%	4.89%	4.94%	5.16%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate

The forecast of Treasury yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated July 1, 2006

Year	Quarter	1-Year Treasury Bill	2-Year Treasury Note	5-Year Treasury Note	10-Year Treasury Note	30-Year Treasury Bond
2006	Third	5.3%	5.3%	5.3%	5.3%	5.3%
2006	Fourth	5.4%	5.3%	5.3%	5.3%	5.4%
2006	First	5.4%	5.3%	5.3%	5.3%	5.4%
2007	Second	5.3%	5.2%	5.2%	5.3%	5.4%
2007	Third	5.2%	5.1%	5.2%	5.3%	5.4%
2007	Fourth	5.1%	5.0%	5.1%	5.3%	5.3%

Petitioner's Exhibit No. PRM-2
Vectren South-Gas
Page 26 of 30
Schedule 11 [5 of 6]

THE VALUE LINE® Investment Survey®

Part 1 Summary & Index

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

May 5, 2006

TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number

SCREENS

The Median of Estimated
PRICE-EARNINGS RATIOS
of all stocks with earnings

19.2

26 Weeks Ago	Market Low 10-9-02	Market High 3-7-05
17.7	14.1	18.9

The Median of Estimated
DIVIDEND YIELDS
(next 12 months) of all dividend paying stocks under review

1.6%

26 Weeks Ago	Market Low 10-9-02	Market High 3-7-05
1.7%	2.4%	1.6%

The Estimated Median Price
APPRECIATION POTENTIAL
of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

40%

26 Weeks Ago	Market Low 10-9-02	Market High 3-7-05
50%	115%	40%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

*Reviewed in this week's issue.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LXI, No. 36.

Published weekly by VALUE LINE PUBLISHING, INC. 220 East 42nd Street, New York, N.Y. 10017-5891

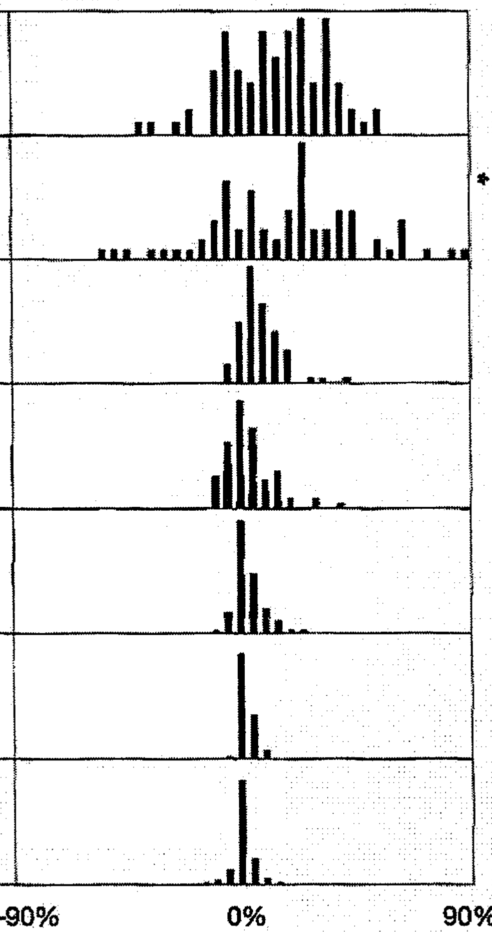
Petitioner's Exhibit No. PRM-2
Vectren South-Gas
Page 27 of 30
Schedule 11 [6 of 6]

Table 2-1

Basic Series: Summary Statistics of Annual Total Returns

from 1926 to 2005

Series	Geometric Mean	Arithmetic Mean	Standard Deviation	Distribution
Large Company Stocks	10.4%	12.3%	20.2%	
Small Company Stocks	12.6	17.4	32.9	*
Long-Term Corporate Bonds	5.9	6.2	8.5	
Long-Term Government	5.5	5.8	9.2	
Intermediate-Term Government	5.3	5.5	5.7	
U.S. Treasury Bills	3.7	3.8	3.1	
Inflation	3.0	3.1	4.3	



*The 1933 Small Company Stocks Total Return was 142.9 percent.

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 3, 4 & 5; Safety Rank of 1 & 2; Financial Strength of B+, B++ & A;
Price Stability of 95 to 100; Betas of .65 to .90; and Technical Rank of 3 & 4

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Assoc. Banc-Corp	BANKMID	4	2	B++	100	0.90	3
Banta Corp.	PUBLISH	4	2	B++	95	0.80	3
Campbell Soup	FOODPROC	3	2	B++	100	0.70	3
Capitol Fed. Fin'l	THRIFT	4	2	B++	95	0.65	3
Cincinnati Financial	INSPRPTY	3	2	B++	100	0.90	3
City National Corp.	BANK	4	2	B++	95	0.80	3
Clorox Co.	HOUSEPRD	4	2	B++	95	0.65	3
Commerce Bancshs.	BANKMID	4	1	A	100	0.85	3
ConAgra Foods	FOODPROC	4	2	B++	95	0.70	3
First Midwest Bancorp	BANKMID	4	2	B++	100	0.85	3
Harte-Hanks	ADVERT	4	1	A	95	0.90	3
Hormel Foods	FOODPROC	3	1	A	95	0.70	3
Huntington Bancshs.	BANKMID	3	2	B++	95	0.90	3
Int'l Flavors & Frag.	CHEMSPEC	3	2	B++	95	0.70	3
Kellogg	FOODPROC	3	2	B++	100	0.65	3
Lee Enterprises	NWSPAPER	5	2	B++	100	0.80	3
Markel Corp.	INSPRPTY	3	2	B++	95	0.75	3
McClatchy Co.	NWSPAPER	5	1	A	100	0.75	3
Mercury General	INSPRPTY	4	2	B++	95	0.85	3
Meredith Corp.	PUBLISH	3	1	A	100	0.85	3
National Presto Ind.	APPLIANC	3	2	B+	95	0.65	4
New York Times	NWSPAPER	4	1	A	95	0.85	3
Old Nat'l Bancorp	BANKMID	3	2	B++	100	0.70	3
Pitney Bowes	OFFICE	3	1	A	95	0.90	3
Protective Life	INSLIFE	4	2	B++	95	0.90	3
Scripps (E.W.) 'A'	NWSPAPER	3	2	B+	100	0.85	3
St. Joe Corp.	HOMEBILD	3	1	A	95	0.85	3
Universal Corp.	TOBACCO	5	2	B++	95	0.75	3
Average		4	2	B++	97	0.79	3
Gas Group	Average	4	2	B++	94	0.82	3

Source of Information: Value Line Investment Survey for Windows, May 5, 2006

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2001-2005 and
Projected 3-5 Year Returns

Company	2001	2002	2003	2004	2005	Average	Projected 2009-11
Assoc. Banc-Corp	16.8%	16.6%	17.0%	12.8%	13.8%	15.4%	15.5%
Banta Corp.	14.2%	13.3%	11.7%	12.6%	13.5%	13.1%	13.5%
Campbell Soup	-	-	161.8%	74.7%	55.7%	97.4%	25.0%
Capitol Fed. Fin'l	7.4%	9.1%	5.3%	4.8%	7.5%	6.8%	7.5%
Cincinnati Financial	3.2%	5.4%	6.2%	8.4%	9.2%	6.5%	8.0%
City National Corp.	16.4%	16.3%	15.3%	15.3%	16.1%	15.9%	16.5%
Clorox Co.	20.2%	23.8%	42.3%	35.5%	35.5%	31.5%	49.0%
Commerce Bancshs.	14.3%	14.1%	14.2%	15.4%	16.7%	14.9%	14.0%
ConAgra Foods	17.1%	18.2%	18.2%	16.4%	14.5%	16.9%	13.0%
First Midwest Bancorp	18.4%	18.3%	17.8%	18.6%	18.6%	18.3%	20.0%
Harte-Hanks	14.4%	17.0%	15.7%	17.1%	20.5%	16.9%	18.5%
Hormel Foods	18.3%	17.0%	14.8%	15.6%	16.1%	16.4%	16.0%
Huntington Bancshs.	12.1%	14.8%	17.0%	15.7%	16.1%	15.1%	14.0%
Int'l Flavors & Frag.	25.8%	32.0%	26.9%	21.5%	20.5%	25.3%	17.5%
Kellogg	61.1%	79.4%	54.5%	39.5%	42.9%	55.5%	27.5%
Lee Enterprises	9.7%	9.6%	9.7%	9.8%	10.3%	9.8%	10.5%
Markel Corp.	NMF	3.2%	6.1%	9.8%	7.8%	6.7%	13.5%
McClatchy Co.	6.3%	12.5%	11.9%	11.1%	10.5%	10.5%	10.0%
Mercury General	9.8%	10.2%	14.1%	18.4%	15.1%	13.5%	15.5%
Meredith Corp.	17.8%	11.2%	18.4%	18.8%	19.7%	17.2%	20.5%
National Presto Ind.	2.7%	3.6%	6.3%	6.0%	7.3%	5.2%	10.0%
New York Times	22.2%	24.1%	21.5%	20.9%	15.5%	20.8%	16.0%
Old Nat'l Bancorp	15.5%	14.8%	9.8%	9.6%	12.1%	12.4%	14.5%
Pitney Bowes	62.4%	67.0%	52.3%	46.0%	48.1%	55.2%	35.5%
Protective Life	10.1%	10.0%	9.8%	10.9%	12.1%	10.6%	11.5%
Scripps (E.W.) 'A'	10.6%	15.2%	13.6%	13.8%	14.0%	13.4%	14.0%
St. Joe Corp.	10.9%	31.5%	15.6%	17.2%	24.6%	20.0%	19.0%
Universal Corp.	21.4%	18.1%	18.3%	13.5%	10.5%	16.4%	13.0%
Average						20.6%	17.1%
Median						15.6%	15.0%

Southern Indiana Gas and Electric Compnay

Rate of Return Applicable to a Fair Value Rate Base

Investor Provided Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	45.10%	6.04%	2.72%
Common Equity	54.90%	10.31%	5.66%
Total	100.00%		8.38%

For Ratesetting Purposes	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	38.65%	6.04%	2.33%
Common Equity	47.05%	10.31%	4.85%
Customer Deposits	0.48%	5.39%	0.03%
Cost-free Capital	13.06%	0.00%	0.00%
JDITC	0.76%	8.38%	0.06%
Total	100.00%		7.27%

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH – GAS)

IURC CAUSE NO. 43112

DIRECT TESTIMONY

OF

ROBERT L. GOOCHER
VICE PRESIDENT AND TREASURER

ON

COST OF CAPITAL

SPONSORING PETITIONER'S EXHIBITS RLG-1 THROUGH RLG-3

DIRECT TESTIMONY OF ROBERT L. GOOCHER

I. INTRODUCTION

Q. Please state your name and business address.

A. Robert L. Goocher
One Vectren Square
Evansville, Indiana.

Q. What is your position with Southern Indiana Gas & Electric Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or the "Company")?

A. I am Vice President and Treasurer of Vectren South. I also hold these same positions with Vectren Corporation ("Vectren"), Vectren Utility Holdings, Inc. ("VUHI"), Indiana Gas Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren North") and Vectren Energy Delivery of Ohio, Inc. ("Vectren Ohio").

Q. What is your educational background?

A. I graduated from the University of Georgia with a Bachelor of Business Administration with a major in accounting and from Georgia State University with a Master of Business Administration with a major in finance.

Q. Please describe your business experience.

A. I have over 30 years' experience in various financial, operational and administrative roles, primarily in the utility and energy industry. I worked at AGL Resources (parent company of Atlanta Gas Light Company) in Atlanta, GA and its predecessor companies in a variety of positions including Assistant Treasurer, Controller, Vice President and Augusta Division Manager, Chief Financial Officer, Executive Vice President-Business Support and President and Chief Operating Officer of AGL's shared services subsidiary. My most recent position prior to joining Vectren was Treasurer for GridSouth Transco in Charlotte, NC. On April 1, 2002, I joined Vectren as Vice President and Treasurer of Vectren, VUHI, and its three operating utilities, as well as a number of its non-regulated subsidiaries. In addition, I have also been appointed to the board of directors of Vectren South and Vectren Capital Corporation.

Q. What are your responsibilities as Vice President and Treasurer of Vectren Corporation, VUHI, Vectren North, Vectren South and Vectren Ohio?

A. I am responsible for maintaining the security and liquidity of the Companies' working capital resources. This includes having responsibility for cash management, bank relations, short-term borrowings, long-term capital financing, leasing, capital allocation, capital resource planning, risk management, credit rating agency relations and a variety of other finance-related activities.

II. SUMMARY OF PRESENTATION

Q. What is the purpose and scope of your testimony in this proceeding?

A. My testimony and accompanying exhibits will provide an overview of the components of Vectren South's capital structure and its weighted average cost of capital. Vectren South's capital structure is the same for both its electric and gas operations since the Company does not attempt to allocate its capital between the two operating divisions. However, Vectren South's weighted average cost of capital is slightly different, as a result of different cost rates for common equity in the gas and electric operations.

III. COST OF CAPITAL

Q. How does Vectren South finance its operations?

A. Vectren South finances its operations through the issuance of securities (long-term debt and common stock). Although Vectren South still has some outstanding debt issues that existed at the time of the Vectren merger on March 31, 2000, all of Vectren South's additional permanent debt financing requirements have been accomplished through VUHI. It is Vectren's intention to continue to use VUHI as the principal entity to provide permanent debt financing for all of Vectren's utility subsidiaries, including Vectren South. One exception to this could be any tax exempt financing related to qualifying environmental expenditures which would likely have to be issued directly by Vectren South.

Q. What is your estimate of Vectren South's weighted average cost of capital?

A. In my opinion, Vectren South's cost of capital is 7.96%. Petitioner's Exhibit No. RLG-2 shows how I derived this estimate.

Q. Please describe the investor-provided capital structure components that you have reflected in the computation of Vectren South's cost of capital.

A. Petitioner's Exhibit No. RLG-2, include Vectren South's investor-provided capitalization as of March 31, 2006. This results in an investor-provided capital structure consisting of 45.10% long-term debt and 54.90% common equity.

Q. How do these capital structure ratios compare with Vectren South's financial objectives?

A. These ratios seem to be generally supportive of its financial objectives. Vectren South currently has senior unsecured debt ratings of "Baa1" from Moody's Investors Service (stable outlook) and "A-" from Standard & Poor's Ratings Services (stable outlook). Vectren's goal for VUHI, Vectren North and Vectren South is to achieve and maintain a solid "A" credit rating for the senior unsecured debt. However, given that current credit ratings are below this benchmark, improvements will need to be made in various earnings and cash flow related financial metrics to achieve this goal. Continued improvements in these various financial metrics should provide Vectren South with the opportunity to maintain and improve current rating levels over time.

Q. What is the weighted cost of the long-term debt portion of Vectren South's capital structure?

A. As shown on Petitioner's Exhibit No. RLG-3, Vectren South's weighted cost of long term debt is 6.04%. The details leading to the development of the effective cost rate for each series of long-term debt, using the cost rate to maturity technique, are shown on Petitioner's Exhibit No. RLG-3. The cost rate is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the long-term debt, *i.e.* the gross proceeds less issuance costs. This methodology is consistent with that used in the most recent Vectren South - Gas rate proceeding, in Cause No. 42596, in the recently concluded Vectren South – Electric Multi-pollutant proceeding in Cause No. 42861 and in Vectren North's most recent rate proceeding in Cause No. 42598.

Q. Were there any changes to Vectren South's investor provided capitalization during the test year?

A. Yes. In September 2005, Vectren South sold $125 million of its common equity to VUHI, its immediate parent. In March 2006, it sold another $20 million of common equity to VUHI. Finally in March 2006, VUHI loaned Vectren South $25 million of the proceeds of its November 2005 issuance of 6.10% Senior Notes due December 1, 2035 and $50 million of the proceeds of its 5.45% Senior Notes due December 1, 2015, which were issued by VUHI in November 2005.

Q. Why were these actions taken?

A. The last incremental permanent financing at Vectren South prior to the test year financing was in the fall of 2003 when both debt and equity was issued. In 2004 and 2005, Vectren South had capital expenditures totaling approximately $257 million, much of which was related to environmental expenditures to reduce NOx emissions at its electric generating plants. The capital expenditures were initially funded with internally generated funds and with short-term debt, which was replaced with permanent debt and equity financing during the test year.

This financing is consistent with the plans outlined in Vectren South's financing petition in Cause No. 42807 approved by the Commission on May 11, 2005. The Order granted Vectren South financing authority through December 31, 2007 for the issuance of up to $170 million of common or preferred stock and up to $105 million of long-term debt. Thus, financing authority for the issuance of up to an additional $25 million of common or preferred stock and up to $30 million of long-term debt remains available under the financing Order. The test year financing is also consistent with Vectren South's financing plans outlined by Petitioner's witness, Jerome A. Benkert, Jr. in his testimony in Cause No. 42861 in the Multi-pollutant proceeding approved by the Commission on February 22, 2006.

Q. **Has Vectren South remarketed any of its existing long term debt during the test year?**

A. Yes. Thirty one and a half million dollars of the 4.75% series and $22.2 million of the 5.0% series of Vectren South's tax exempt debt was required to be remarketed in March 2006. These two debt issues were converted to variable rate debt in March 2006 and are currently being repriced in the 7-day tax-exempt auction rate market. The interest rates on these two debt issues at March 31, 2006 that were used in the computation of cost of debt in this proceeding were 3.40% for the $31.5 million issue and 3.65% for the $22.2 million issue. At June 30, 2006 these interest rates were 4.11% and 4.31%, respectively.

Q, **Were there any benefits or costs included in the calculation of the effective interest rate of the new $25 million in VUHI debt that was loaned to Vectren South in March 2006 related to interest rate hedging activities?**

A. Yes. VUHI hedged a portion of its interest rate risk related to the new 6.10% 30-year debt issue due December 1, 2035, prior to issuance by utilizing Forward Starting Swaps. Interest rates rose following the execution of the interest rate hedges resulting in a gain of $0.6 million related to the $25 million Vectren South long-term debt proceeds provided by VUHI. This gain will be amortized over the 30-year life of Vectren South's new debt issue as a reduction in interest expense, as provided in the financing Order received in Cause No. 42807. The proceeds from hedging more than offset the cost of issuance of the debt, resulting in an effective interest rate of 5.99% or 11 basis points less than the stated interest rate paid to investors.

Q. What common equity cost rate did you use?

A. A cost rate of common equity of 11.75% was used in the determination of the overall cost of capital. Petitioner's Witness Paul R. Moul is testifying regarding Vectren South's cost of common equity capital (see Petitioner's Exhibit No. PRM-1).

Q. What impact did the test year financing have on Vectren South's capital structure and its weighted average cost of capital?

A. In Cause No. 42861 for Vectren South's Multi-pollutant proceeding, its cost of capital was determined to be 7.98% at June 30, 2005 and is estimated to be 7.96% at March 31, 2006 following the permanent financing previously discussed. Investor provided capital increased from approximately $772 million to just over $1 billion and the proportion of common equity increased to 54.9% compared to 51.2% at June 30, 2005. Thus, even with the significant amount of new financing undertaken and the rebalancing of proportions of debt and equity used in its permanent capital structure to more appropriate levels, the changes in the various cost rates and levels of other components of capital structure resulted in a modest 2 basis point decrease in Vectren South's overall weighted average cost of capital.

Q. Does Petitioner's Exhibit No. RLG-2, include other capital structure components for purposes of determining Vectren South's cost of capital?

A. Yes. That exhibit includes customer deposits, as required by the Commission's rules, at the 5.39% weighted average interest rate and Job Development Investment Tax Credits ("JDITC") at the overall weighted cost of investor-provided capital. The 5.39% interest rate for customer deposits was calculated by determining the amounts of customer deposits attributed to gas service and to electric service. The current gas deposit interest rate of 4.5% and electric of 6.0% were weighted to arrive at the 5.39% blended interest rate.

Q. Were there any cost-free components included in determining Vectren South's cost of capital?

A. Yes. Accumulated deferred income taxes, customer advances for construction and Statement of Financial Accounting Standards No. 106 ("SFAS 106") costs in excess of the cash basis (or pay-as-you-go) amounts were included at zero cost.

Q. Please explain how the accumulated deferred tax balance shown on <u>Petitioner's Exhibit No. RLG-2</u> was calculated.

A. Statement of Financial Accounting Standards No. 109 ("SFAS 109"), "Accounting for Income Taxes," of the Financial Accounting Standards Board requires deferred income taxes to be provided on the difference between the tax basis of assets and liabilities and the amounts at which they are carried in the financial statements. SFAS 109 requires regulated enterprises to provide deferred taxes on all temporary differences including those not previously recognized when the tax effect of the differences are, at the direction of regulatory authorities, essentially flowed through to the customers' benefit for ratemaking purposes. Regulated enterprises are also required to recognize regulatory assets and liabilities for the effect on revenues expected to be realized as the tax effects of temporary differences reverse.

To adjust the deferred income tax liability to the gross amount, the above mentioned regulatory assets and liabilities were recorded in the deferred taxes account through a reclassification entry, which affects only the balance sheet. For consistency with prior rate cases and for simplicity of presentation, these regulatory assets and liabilities have been netted against the long-term deferred income tax liability. The result is a deferred income tax balance included in the capitalization, which is on the same basis as that recognized in previous rate cases.

Q. Please explain how the SFAS 106 amount included as cost-free capital was determined.

A. The cumulative SFAS 106 costs incurred by Vectren South in excess of cash payments made and amounts funded in VEBA trusts, since the Commission authorized an increase in Vectren South's electric rates effective May 3, 1995, have been included at zero cost. This approach is consistent with the Commission's generic Order regarding SFAS 106 costs dated December 30, 1992 in Cause No. 39348 and with the approach utilized by Vectren North in its most recent rate case in Cause No. 42598, approved by the Commission on November 30, 2004. The $11.536 million component of cost-free capital was derived first by subtracting the SFAS 106 liability of $8.384 million that existed at December 31, 1994 for Vectren South's Postretirement Medical Plan from the estimated liability of $25.042 million that exists at March 31, 2006 for that Plan. The $16.658 million increase in the liability over this period results from the net of the additional annual SFAS 106 accruals less the amount of contributions made to the VEBA trusts and benefits actually paid for each year. The final step in arriving at the proper amount to include as cost-free capital is to reduce the $16.658 million difference by 30.75%, which is the percentage of various costs that are capitalized and thus not included for recovery in operation and maintenance expenses. The $11.536 million remainder was then included in Vectren South's capital structure as cost-free capital.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

VECTREN SOUTH COST OF CAPITAL
Capital Structure at March 31, 2006
($000's)

Line		Actual at 3-31-06	Ratios	Cost	WCOC
1	**Long-Term Debt**				
2	Publicly Held	228,165	19.54%		
3	Notes to VUHI	223,182	19.11%		
4	Total Long-Term Debt	451,347	38.65%	6.04%	2.33%
5					
6	**Common Equity**				
7	Common Stock	$273,263	23.40%		
8	Retained Earnings	274,999	23.55%		
9	Accumulated Comprehensive Income	1,246	0.11%		
10	Common Shareholder's Equity	549,508	47.05%	11.75%	5.53%
11					
12	**Total Investor Provided Capital**	1,000,855	85.70%		7.86%
13					
14	**Customer Deposits**	5,601	0.48%	5.39%	0.03%
15					
16	**Cost-Free Capital**				
17	Deferred Income Taxes	138,730	11.88%		
18	Customer Advances for Construction	2,211	0.19%		
19	SFAS 106	11,536	0.99%		
20	Total Cost Free Capital	152,477	13.06%	0.00%	0.00%
21					
22	**Job Development Investment Tax Credit (Post-1971)**	8,920	0.76%	9.17%	0.07%
23					
24	**Total Capitalization**	$1,167,853	100.00%		7.96%
25					
26	**Investor Provided Capital**				
27					
28		**Amount**			
29		**($000's)**	**Percent**	**Cost**	**WCOC**
30	Long Term Debt	$451,347	45.10%	6.04%	2.72%
31					
32	Common Equity	549,508	54.90%	11.75%	6.45%
33	Total Capitalization	$1,000,855	100.00%		9.17%

Vectren South
Schedule of Long-Term Debt
3/31/2006

	Long-Term Debt	Date of Issue	Maturity Date	Principal Amount Outstanding	Type	Total Discount and Expense Net of Premium	Net Proceeds	Effective Cost Rate	Annual Interest Expense
1	*6.625% Series	12/01/01	12/01/11	$ 86,584,802	FMB		$ 86,584,802	6.80%	$ 5,888,395
2	3.28% Series	07/01/85	07/01/15	9,775,000	FMB	$ 336,163	9,438,837	3.67%	320,620
3	8.875% Series	06/16/86	06/01/16	13,000,000	FMB	2,066,030	10,933,970	9.18%	1,153,750
4	**5.750% Series	07/01/03	07/01/18	61,880,458	FMB	6,583,471	55,296,987	7.04%	3,633,781
5	4.500% Series	04/30/03	03/01/20	4,640,000	FMB	397,137	4,242,863	5.27%	208,800
6	3.65% Series	05/01/93	05/01/23	22,550,000	FMB	1,191,354	21,358,646	4.05%	823,075
7	4.650% Series	04/30/03	03/01/24	22,500,000	FMB	2,937,787	19,562,213	5.74%	1,046,250
8	3.40% Series	03/01/98	03/01/25	31,500,000	FMB	920,138	30,579,862	3.62%	1,071,000
9	6.720% Series	08/01/99	08/01/29	80,000,000	FMB	620,720	79,379,280	6.78%	5,376,000
10	3.65% Series	03/01/98	03/01/30	22,200,000	FMB	1,039,367	21,160,633	3.96%	810,300
11	5.000% Series	04/30/03	03/01/30	22,000,000	FMB	2,167,561	19,832,439	5.73%	1,100,000
12	***6.10% Series	11/16/05	12/01/35	25,284,481	FMB		25,284,481	5.99%	1,515,517
13	****5.45% Series	11/16/05	12/01/15	49,432,013	FMB		49,432,013	5.63%	2,781,799
14									
15				$ 451,346,754		$ 18,259,729	$ 433,087,025	6.04%	$ 25,729,287
16									
17									
18									

19 *The coupon rate at the VUHI level is 6.625% on a gross amount of $87,500,000. SIGECO has an effective rate
20 of 6.80% on the net amount of $86,584,802 in order to reimburse VUHI for the interest and net amortization expense.
21
22 **The coupon rate at the VUHI level is 5.75% on a gross amount of $62,500,000. SIGECO has an effective rate
23 of 5.87% on the net amount of $61,880,458 in order to reimburse VUHI for the interest and net amortization expense.
24
25 ***The coupon rate at the VUHI level is 6.10% on a gross amount of $25,000,000. SIGECO has an effective rate
26 of 5.99% on the net amount of $25,284,481 in order to reimburse VUHI for the interest and net amortization expense.
27
28 ****The coupon rate at the VUHI level is 5.45% on a gross amount of $50,000,000. SIGECO has an effective rate
29 of 5.63% on the net amount of $49,432,013 in order to reimburse VUHI for the interest and net amortization expense.